BRIEF

Submitted Jointly By

MOBIL OIL OF CANADA LTD.

And

PAN AMERICAN PETROLEUM CORPORATION

To The

ROYAL COMMISSION ON ENERGY

(THE BORDEN COMMISSION)

Concerning

Production and Conservation in the Pembina Field of the Province of Alberta

APRIL 1958

Exhibit CC - 15 - 3

B R I E F

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WITNESSES AVAILABLE FOR EXAMINATION

IN SUPPORT OF THE WITHIN SUBMISSION

S. B. RICHARDS

B.Sc. in Petroleum Engineering, University of Oklahoma - 1939. Member of the Alberta Association of Professional Engineers. Member of the American Institute of Mining, Metallurgical and Petroleum Engineers. Chairman, Engineering Committee of the Pembina Operators Committee.

Present Position:	Division Engineer, Pan American Petroleum Corporation
Past Experience:	Employed by Pan American Petroleum Corporation in various petroleum engineering capacities from June, 1939 until the present time.

P. A. TAYLOR

Honours B.Sc. in Petroleum Engineering, Birmingham University, England - 1936. Member of the Alberta Association of Professional Engineers. Member of the Canadian Institute of Mining and Metallurgy. Member of the Institute of Petroleum.

Present Position:	Chief Petroleum Engineer, Mobil Oil of Canada, Ltd.
Past Experience:	Petroleum Engineer for twenty-two years of which sixteen years were with Shell Oil Co. and six years with Mobil Oil of Canada, Ltd.

Note: Both Mr. S.B. Richards and Mr. P.A. Taylor will be available for examination in respect to matters contained in Sections II through IX.

B.C. EDWARDS

B.Sc. in Chemical Engineering, Texas A & M College - 1947. Chairman, Joint Area Committee organized by the Pembina Producers.

Present Position: Division Gas Superintendent, Pan American Petroleum Corporation

Past Experience: Eleven years experience in the gas industry on design, construction and operation of plants and gas sales operations.

C.R. YARBROUGH

B.Sc. in Chemical Engineering, Oklahoma A & M College - 1948. Member of various Committees.

Present Position: Staff Engineer (Gas), Mobil Oil of Canada, Ltd.

Past Experience: Served as gas engineer, district gas engineer and plant foreman with Magnolia Petroleum Co. for eight years and with Mobil Oil of Canada, Ltd. for the past one and one-half years.

Note: Both Mr. B.C. Edwards and Mr. C.R. Yarbrough will be available for examination in respect to matters contained in Section X.

A Submission to the

ROYAL COMMISSION ON ENERGY
(The Borden Commission)

Concerning

Production and Conservation in the Pembina Field of the Province of Alberta

SECTION I

Introduction

Intention:

The purpose of this submission is to inform the members of this Royal Commission concerning various aspects of production and conservation in the Pembina Field of the Province of Alberta with reference to the costs incurred in such operations.

Parties:

This submission is being made jointly by Mobil Oil of Canada, Ltd. and Pan American Petroleum Corporation. Each of these Companies is registered under the provisions of the Companies Act of the Province of Alberta to carry on business in this Province, and each is currently engaged in producing operations. Between them these Companies have some twenty years of experience in the oil and gas industry in Alberta where their individual efforts have been relatively successful. Each has been active in the Pembina Field of this Province since its discovery, and it was felt that they could contribute something of value to the Commission's hearing.

Scope:

This brief will be limited to a discussion of production and conservation problems as they relate to petroleum and natural gas in the Cardium reservoir of the Pembina Field in the Province of Alberta, with particular reference to capital expenditures. There will be considerable technical evidence given.

Method:

The general format of this brief is set out in the table of contents. The geographical location of the Field, the facilities installed, the development phase, reservoir performance, primary and secondary recovery and gas conservation will be considered, and in each phase reference will be made to the large expenditures incurred.

Reasons for Discussing the Pembina Field:

The reasons for selecting the Cardium reservoir of the Pembina Field on which to base this discussion are many.

Firstly, it is the largest field in Canada, not only in areal extent but in the amount of oil in place and in its current producing rate.

Secondly, although it is a newly discovered field, development drilling is almost completed, and producing and conservation problems are paramount.

Thirdly, the geography, geology and reservoir characteristics of the field are such that many, although

not all, of the producing and conservation problems that are met throughout the Province as a whole are encountered, which problems, because of the importance of this field, must be met and overcome.

Fourthly, recent production history has introduced problems of conservation that are becoming increasingly important, and the solution thereof is absorbing much thought, effort and money on the part of the various operators.

Fifthly, the field is typical in the manner in which lands are acquired and held, and in the diversity of ownership thereof.

Conclusion:

From the foregoing, it will be seen that few other fields in the Province of Alberta would present the variety of problems that have been encountered in the Pembina Field. At the end of this brief there will appear a summary of the costs incurred in development, production and conservation operations undertaken by these operators.

S E C T I O N   I I

Geographical Location

The Pembina oil field is located in West Central Alberta, approximately 88 miles west-southwest of Edmonton. The field is approximately 35 miles long by 35 miles wide. (Exhibit II A). When the original discovery was made the area was practically devoid of road or telephone communications. The North Saskatchewan River divides the main development area approximately one third of the way north from the southernmost limits of development. Generally speaking, the area is one of gently rolling hills densely covered with secondary growth poplar and spruce and large poorly drained areas of muskeg. Locally, where the Saskatchewan and Pembina Rivers and their tributaries cut the field, there are steep escarpments which are saturated with water and in most cases are very unstable. The population prior to field development was limited to the inhabitants of a few scattered ranches and the small villages of Drayton Valley and Alder Flats. The total population probably did not exceed 1000 people. Railway entry to the area, although somewhat distant from the main area of development, is by Canadian National Railways to the north approximately 25 miles, and Canadian Pacific Railways to the south-east approximately 15 miles.

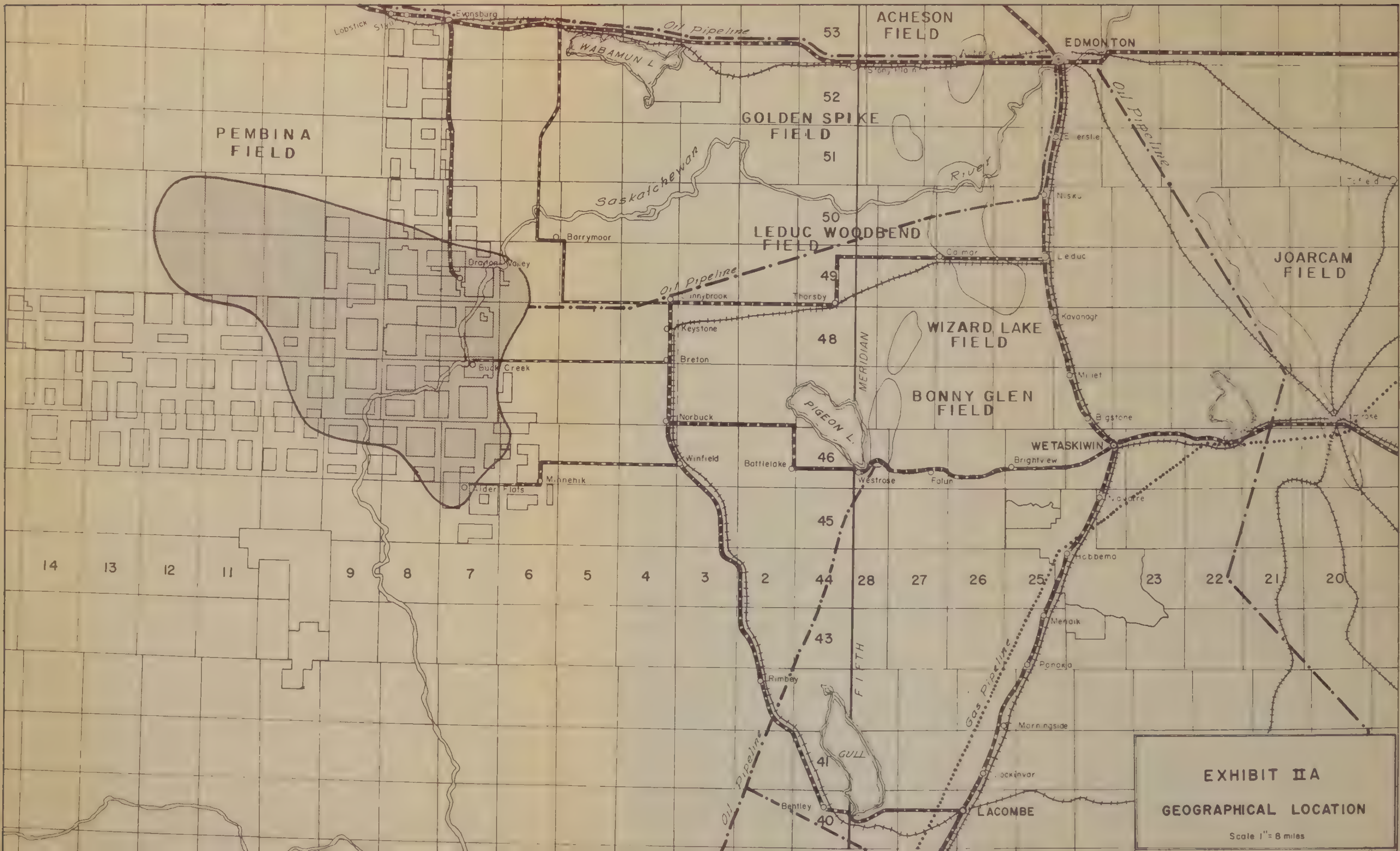


EXHIBIT IIA
GEOGRAPHICAL LOCATION
Scale 1" = 8 miles

SECTION III

Leasing Development

Prior to the discovery of the Pembina Field, acreage was held principally in the reservation form. (Exhibit III A). This covered 762,080 acres. Subsequent to the discovery of oil, and as required by Provincial regulations, the first reservation areas were converted to leases in the central part of what is now the main producing area of the field. At roughly the same time as this conversion took place, the Oil and Gas Conservation Board declared the first field limits. The picture thus at February 1, 1954, broke down to 4,806 lease acres within the field and 11,088 lease acres outside the limits (refer to Figure III B) as chosen by the Oil and Gas Conservation Board. The field was developed at a rapid pace with further reservations being made available within the field area, and the field itself being extended to cover reservations which were not considered in the first instance in February, 1954. Effective February 6, 1958, the reservation situation within the area as delineated by the Oil and Gas Conservation Board as Pembina Field has ceased to exist. As shown on Exhibit III C, the total field area is 369,820 acres of which 303,685 acres are under lease. Some 193,580 acres of this leased acreage was converted to lease from original

reservations, 12,345 acres were held in previous leases, and 97,760 acres have been purchased by operating companies from the Crown at a total cost of $119,729,243.34. The balance of the lands are Hudson Bay Grant and drilling reservation. As shown on Exhibit III C, this substantially fills out the area within the designated field limits, leaving 56,000 acres still in Crown lease status. Of the original acreage as shown under reservation and which might be considered as possibly productive, 215,543 acres have been converted to lease status outside the present field limits.

As a result of this above situation, there are at present 74 working interest owners in the field who own properties in various combinations, as shown in Exhibit III D. Early in the producing history, a committee of operators was formed on a permanent basis to deal with such mutual problems as might arise. The Pembina Operators' Committee has established a permanent staff which compiles and distributes pertinent field information on a regular basis to all participants. All major decisions which have been made are a result of co-operative efforts of this Committee. The Oil and Gas Conservation Board has dealt with field-wide problems primarily through this Committee, and has used this Committee as a sounding board for discussions of pertinent regulations affecting the Pembina Field.

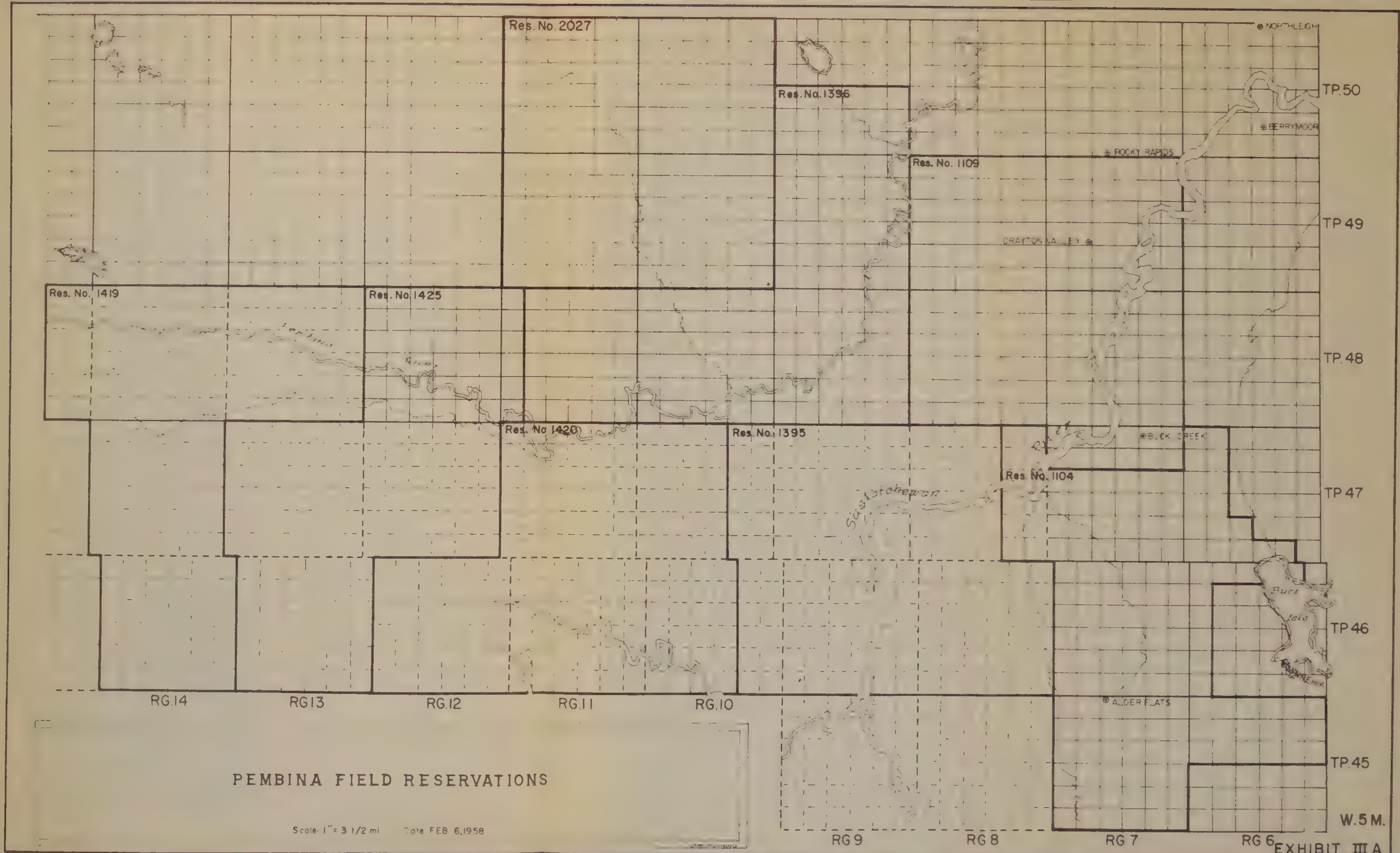
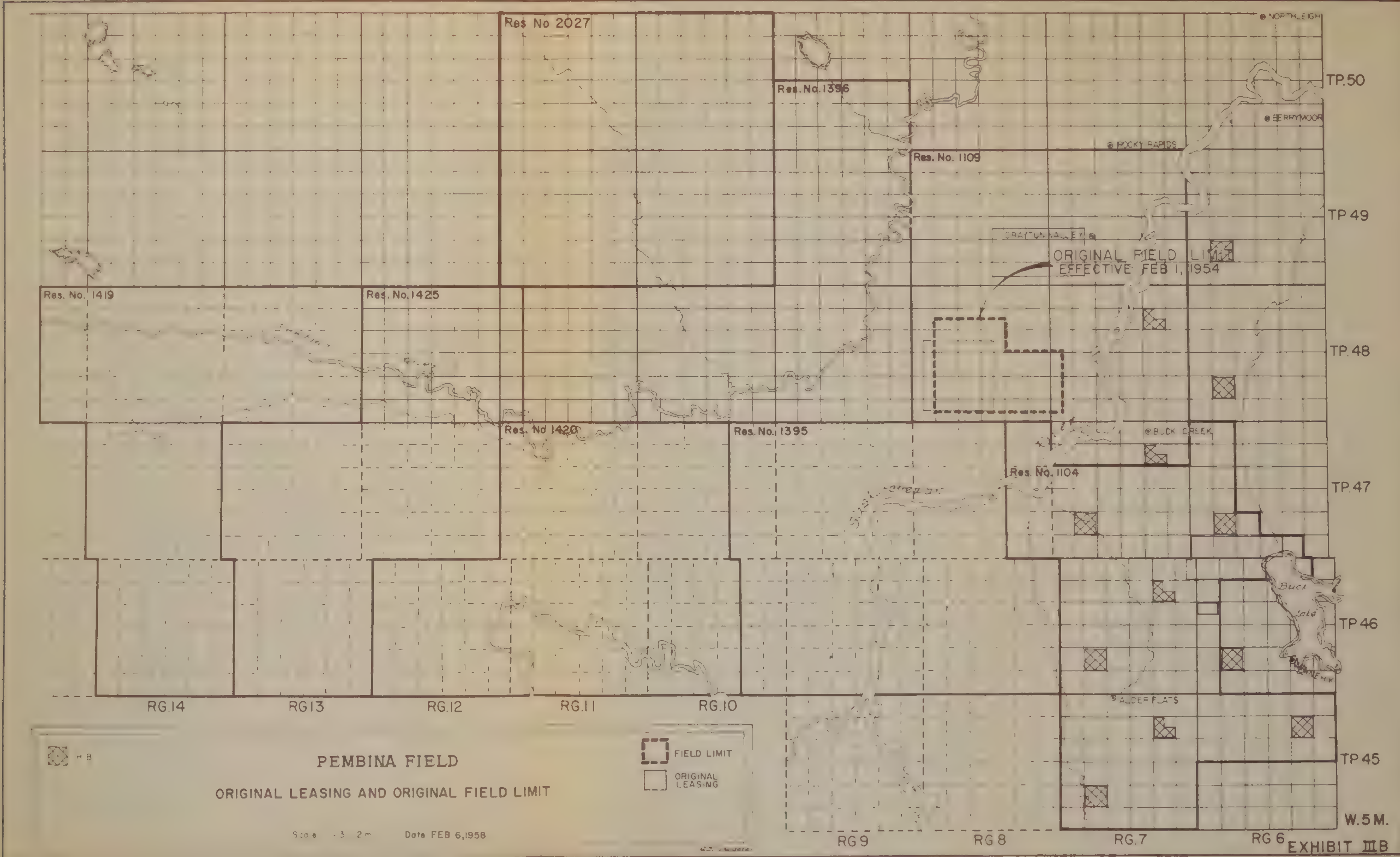
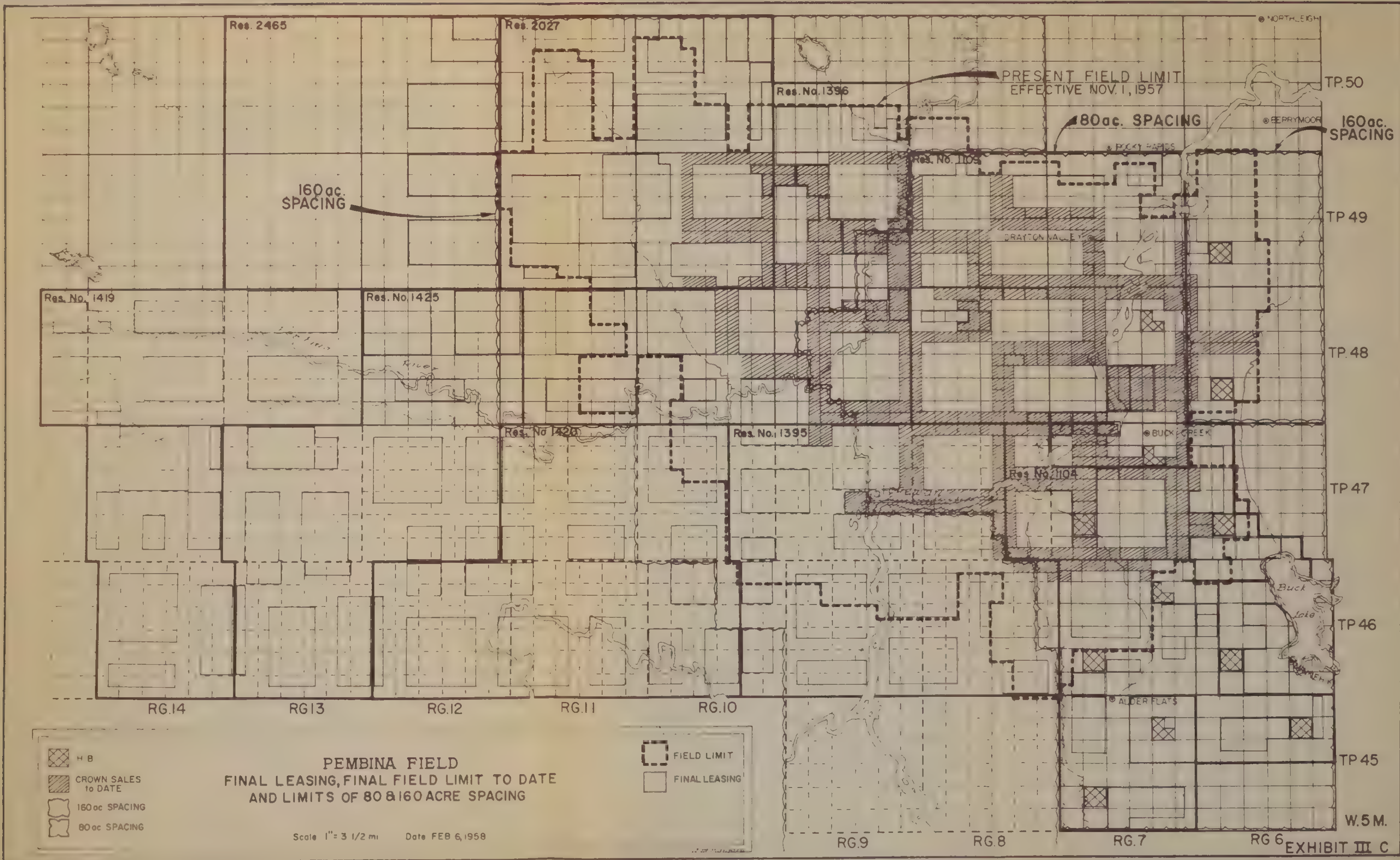


EXHIBIT III A


Res No 2027
Res. No. 1396
Res. No. 1109
Res. No. 1419
Res. No. 1425
Res. No 1426
Res. No. 1395
Res. No. 1104
ORIGINAL FIELD LIMIT
EFFECTIVE FEB 1, 1954
NORTH LEIGH
BERRYMOOR
ROCKY RAPIDS
BUCK CREEK
ALDER FLATS
Buck Lake
TP.50
TP 49
TP.48
TP.47
TP 46
TP 45
W.5 M.
RG.14
RG13
RG.12
RG.11
RG.10
RG 9
RG 8
RG.7
RG 6
FIELD LIMIT
ORIGINAL LEASING
PEMBINA FIELD
ORIGINAL LEASING AND ORIGINAL FIELD LIMIT
Date FEB 6, 1958
EXHIBIT IIIB



PEMBINA FIELD
FINAL LEASING, FINAL FIELD LIMIT TO DATE
AND LIMITS OF 80 & 160 ACRE SPACING
Scale 1" = 3 1/2 mi
Date FEB 6, 1958
H B
CROWN SALES to DATE
160 ac SPACING
80 ac SPACING
FIELD LIMIT
FINAL LEASING
PRESENT FIELD LIMIT
EFFECTIVE NOV. 1, 1957
80 ac. SPACING
160 ac. SPACING
160 ac. SPACING
Res. 2465
Res. 2027
Res. No. 1396
Res. No. 1105
Res. No. 1419
Res. No. 1425
Res. No. 1420
Res. No. 1395
Res. No. 1104
NORTHLEIGH
BERRYMOOR
ROCKY RAPIDS
DRAYTON VALLEY
BUCK CREEK
ALDER FLATS
River
Buck
Lake
TP. 50
TP 49
TP. 48
TP 47
TP 46
TP 45
W. 5 M.
RG. 14
RG 13
RG. 12
RG. 11
RG. 10
RG. 9
RG. 8
RG. 7
RG 6
EXHIBIT III C

OPERATORS IN THE PEMBINA FIELD

SHOWN WITH THEIR VARIOUS PARTNERS

Operator	Partners
Pan American Petroleum Corp.	Hudson's Bay Oil and Gas Company
Mobil Oil of Canada, Limited	Honolulu Oil Corporation, Canadian Seaboard Oil Company, Merrill Petroleums Limited
Texaco Exploration Co.	
Canadian Seaboard Oil Company	Honolulu Oil Corporation, Merrill Petroleums Limited, Great Plains Development Co. of Canada, Ltd., Bailey Selburn Oil and Gas Ltd.
Imperial Oil Limited	Canadian Superior Oil of California Ltd.
Cities Service Petroleum Corporation of Canada	
California Standard Company	
Sinclair Canada Oil Company	
British American Oil Company Limited	
Humber Oils	
Canadian Seaboard Oil Company	Honolulu Oil Corporation, Merrill Petroleums Limited
Plymouth Oil Company	Benedum-Trees Oil Company
Ohio Oil Company	
Tennessee Gas Transmission Company	
Imperial Oil Limited	

EXHIBIT III D

Operator	Partners
Northern Natural Gas Producing Company	
Hudson's Bay Oil and Gas Company	
Whitehall Canadian Oils Limited	Westburne Oil Development Limited, Trinidad Central
Bailey Selburn Oil & Gas Ltd.	
Canadian Bishop Oil Limited	
Canadian Delhi Oil Limited	Great Plains Development Co. of Canada Ltd., Bailey Selburn Oil & Gas Ltd., Canadian Seaboard Oil Company
Home Oil Company Limited	United Oils Limited, Geoil Limited
Home Oil Company Limited	United Oils Limited, Alminex Limited, Geoil Limited
Colorado Oil and Gas Ltd.	
Cities Service Petroleum Corporation of Canada	Canadian Seaboard Oil Company, Pan American Petroleum Corp.
Luscar Coals Limited	
Petrol Oil and Gas Co. Ltd.	Canpet Exploration Limited, Fargo Oils Limited, Carleton Oils Limited
Bailey Selburn Oil and Gas Limited	Climax Molybdenum Company, Crow's Nest Pass Coal Company, Southwest Potash Corporation, Consolidated Copper Mines Corporation
McColl Frontenac Oil Co.Ltd.	
Devon-Palmer Oils Limited	
New Superior Oils of Canada Limited	Altex Oils Limited

EXHIBIT III D

Operator	Partners
Sun Oil Company	
Home Oil Company Limited	United Oils Limited, Trans-Border Oils Limited, Alminex Limited
Cree Oil of Canada Limited	
Montreal Trust Company	
Phillips Petroleum Company	
Whitehall Canadian Oils Limited	Murphy Corporation, Westburne Oil Development Ltd., Amurex Oil Company, Ashland
Dome Exploration (Western) Limited	
Anglo Canadian Oil Company (1955) Limited	Kroy Oils Limited
Bailey Selburn Oil and Gas Limited	Okalta Oils Limited
Carleton Oils Limited	Canpet Exploration Limited, Westburne Oil Development Limited
Champlin Oil & Refining Co.	
Dome Exploration (Western) Limited	Trans Empire Oils Limited, French Petroleum Company
Quintis Leaseholds Limited	
Canadian Seaboard Oil Company	Merrill Petroleums Limited
Triad Oil Company Limited	
Whitehall Canadian Oils Limited	Westburne Oil Development Limited
E. Constantine	
Home Oil Company Limited	Foothills, Alminex Limited

Operator	Partners
Luscar Coals Limited	Mountain Park Coals Limited
Scurry Oils Limited	Scurry-Rainbow Oil Limited, Jupiter Oil Ltd.
Alida Oil Company Limited	
Amurex Oil Company	Whitehall Canadian Oils Limited, Murphy Corporation, Westburne Oil Development Ltd.
Amurex Oil Company	Murphy Corporation
Colorado Oil and Gas Limited	West Maygill Gas and Oil Ltd.
Consolidated Mic Mac	Medallion Petroleum Limited
Home Oil Company Limited	Foothills, Alminex Limited
L.D. Smith Development Co.	
New Superior Oils of Canada Limited	Altex Oils Limited
Plymouth Oil Company	
Romac	Pancan, Capcan
Scurry Oils Limited	Scurry-Rainbow Oil Limited
Canadian Seaboard Oil Co.	Cities Service Petroleum Corporation of Canada
Supertest Petroleum Corp. Limited	
Trans Canada Pipe Lines Limited	
Trans Empire Oils Limited	French Petroleum Company
Union Oil Company of Calif.	
United Oils Limited	

EXHIBIT III D

Operator	Partners
Anglo Canadian Oil Company (1955) Limited	Bralsaman Petroleums
Home Oil Company Limited	United Oils Limited, Geoil Limited, Meek-Spalding Syndicate
Mountain Park Coals Limited	Luscar Coals Limited
South Edmonton Scrap Metal	
Trans Canada Pipe Lines Ltd.	New Concord Development Corp. Ltd., Okalta Oils Limited
Trans Canada Pipe Lines Ltd.	Luscar Coals Limited
Whitehall Canadian Oils Ltd.	Trinidad Central

S E C T I O N   I V

Developments

After the completion of the discovery well in the middle of 1953, a number of wells were drilled across the field, spaced at least 4½ miles apart in accordance with regulations which limit development until after reservation has been converted to lease.

The selection of leases having been made, development was first concentrated in the central field leases, and batteries were built for collecting and gauging the oil and gas. The normal 40-acre spacing pattern was considered unnecessary by the early operators for the proper drainage of the reservoir, and, following discussions and a hearing before the Conservation Board, approval was granted to develop the field on 80-acre spacing.

All produced oil was taken out of the field by trucks at a cost ranging from $.75 to $1.00 per barrel until Pembina Pipe Line first started taking oil towards the end of 1954, when the oil was pumped directly from the field to the pipeline terminal in Edmonton. At the present time some oil is still being trucked from isolated locations.

As the development of the field extended, the operators encountered variations in sand thickness

and quality. It was considered that 80-acre spacing was not justified in the areas of poorer sand development, and following further discussions and a hearing before the Conservation Board, 160-acre spacing was established on the western side, and also extended at a later date to the eastern side of the field. (Exhibit III C).

The expansion of activities was rapid, as is shown in the following tabulation of drilling rigs in operation and wells completed for production, at half year intervals: (Exhibit IV A).

		Drilling Rigs in Operation	Cumulative Wells Completed
1954	End	25	135
1955	Middle	44	500
	End	40	796
1956	Middle	59	1218
	End	37	1676
1957	Middle	13	1958
	End	12	2070

The spring thaw each year forces a drastic reduction in activities, due mainly to road bans, for about one to two months. All drilling operations and movement of oil by road trucks necessarily comes to a standstill during these periods. Also periods of extreme cold in winter and unseasonal rains at other times have caused cessation of activities. In consequence of the above, major construction and pipeline work normally has to be concentrated during the summer months.

On the other hand, part of the field area is covered by muskeg, and where this is fairly extensive and deep, it is usual to drill the wells and make the access roads during the winter when the muskeg is frozen.

Aside from these above handicaps, no unusual problems were encountered in the actual drilling operations.

The main feature of the completion of the wells is the need to fracture the producing formation in order to obtain a satisfactory productive capacity of the wells. These fracture operations have to be carefully engineered and supervised, and are a major item in the development costs. The average cost of the treatment is about $5,000 per well, and as nearly every well in the field has been fractured at least once, the total cost for 2,000 wells would be around $10 million.

As soon as a well ceases to make its allowable production by natural flow, pumping units become necessary to raise the oil to the surface. This occurred fairly early in the life of the field. Gas engines were initially used to operate the pumping units. The internal combustion engines were then replaced with electric motors as electrical power was brought into the field.

The unstable nature of the terrain necessitates costly installation of pumping unit bases. In some areas, this involved driving piles in the construction of foundations.

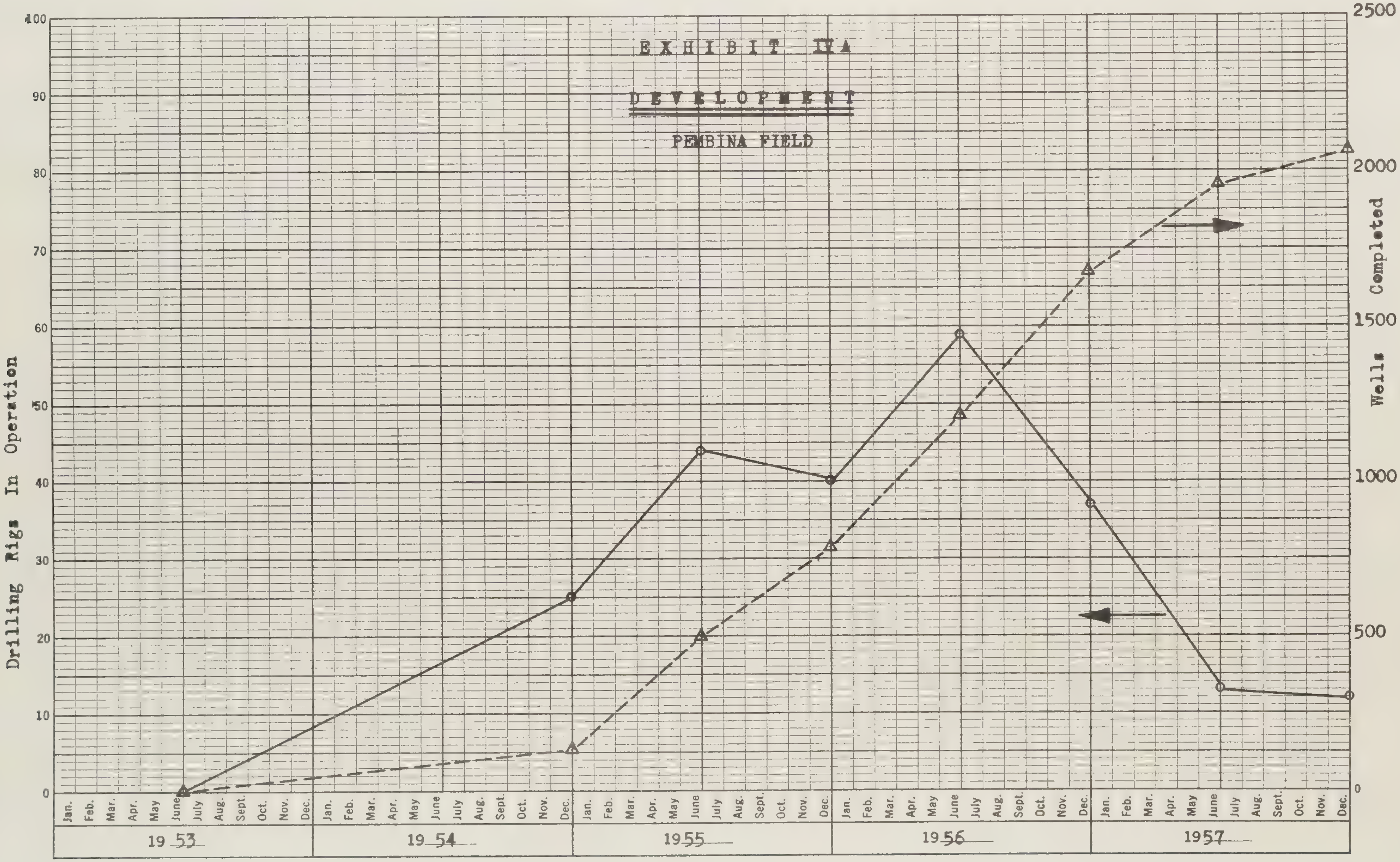


EXHIBIT IIA
DEVELOPMENT
PEMBINA FIELD
Drilling Rigs In Operation
Wells Completed
1953
1954
1955
1956
1957

SECTION V

Facilities

As the development of drilling progressed in the field, it was necessary for the operators to construct, at considerable cost, facilities such as roads, pipelines, housing, communications, etcetera. In addition, the Provincial Government has constructed a main highway, brought in 27 miles from the Edmonton to Jasper highway, and a high level bridge spanning the North Saskatchewan River. The latter replaced a ferry service, which could not be operated during the freeze over and break up periods, but could be replaced by an ice bridge during a cold winter.

The oil companies have built, at a cost of $6.2 million, a network of roads to serve their leases, totalling 450 miles, of which 300 miles are on Government road allowances. In addition to this, the oil companies have built about 430 miles of access roads into wellsites and tank battery locations at a cost of around $5.5 million. In certain muskeg area costs per mile for roads constructed have been as high as $35,000 -- three times normal costs in the field area.

Communications with field operations, both from an efficiency and a safety aspect, were complicated due to the rapid development program, which for the major operators

was widely scattered. Telephone service could not keep pace with this program, and the operators used radio communication extensively. This was not a major cost, as for two of the larger operators the total cost has been $45,000, but it was an important facility in aiding the efficiency of the operations.

Calculated on the basis of the personnel employed by the majors, it is estimated that the oil companies employ about 700 men in the field area in producing operations. This figure is supplemented by all the contractors who do nearly all the drilling, all the cementing, fracturing, well logging, perforating, construction, and the majority of the road-building, oil trucking, and well servicing, and the equipment supply houses. There are also a large number of minor contractors directly involved in the development operations. At the present time it is estimated that there are about 10,500 inhabitants in the oilfield area, of which only a very few are farmers. Additional personnel will be required for the operation of the gas conservation project now under construction. A portion of these personnel are temporarily stationed in the field in connection with development and construction facilities, and will leave the area when these activities are concluded.

At the height of the drilling phase there were about 60 drilling rigs in operation in the field, which required about 1000 men to operate them. These rigs represented a capital investment of about $20 million.

Another major contract service was oilwell cementing and fracturing, and these services at the height of activities employed some 300 men, operating equipment which represented a capital investment of some $4 million.

In the early stages of the operation, personnel were housed in temporary quarters at considerable expense. With the increase in scope of operations, with the accompanying increase in personnel, it was necessary to provide permanent facilities such as houses, workshops, etcetera. The cost of this had of necessity to be borne by operating companies and contractors as the area was unattractive to private investors and lending institutions. The main development was concentrated in the Drayton Valley area and a subsidiary development in the Buck Creek area. In addition, the operating companies found it necessary to construct permanent housing in scattered field areas to provide supervision in these areas. As a matter of fact providing permanent housing was essential to the attraction of the personnel required to operate in the area.

These facilities are estimated to have cost about $4 million, which of course does not include the commercial centre, or private residences. The housing,

office and workshop facilities provided by the cementing and fracturing contractors is estimated to have cost $0.5 million.

There is a further large investment in pipeline outlets and electrical power. The crude oil pipeline involves a system for gathering the oil from the tank batteries of the operator, collecting it at a central point, and then transporting it through the main pipeline to a terminal at Edmonton from where it can be sent to the west coast, the east, or to local refineries. The capital investment in this system was about $22.0 million. The pipeline system has a capacity to handle 150,000 barrels daily. (Exhibit II A).

Cost of a transmission system to bring electric power to the field, together with a distribution grid, entailed the expenditure of approximately $4 million.

S E C T I O N   V I

The Reservoir

The Cardium Formation is the main reservoir for the Pembina Field and occurs in the Colorado Group of Upper Cretaceous Age. Minor reservoirs occur at lesser and greater depths but in view of their small size are not considered in this submission. At the top of the producing formation there is a conglomerate, which is extremely erratic in deposition and variable in thickness, and of minor importance as a reservoir. Below this is the upper sand, which is the main reservoir, and varies in thickness up to 25 feet. This is underlain by a shale member approximately 20 feet in thickness, which in some areas develops over its upper part into a good sand. The basal member is a lower sand of approximately 10 to 15 feet in thickness.

Exhibit VI A is a contour map on the top of porosity of the Cardium. It shows the general direction in which the beds dip to the southwest, with a variation of dip from 30 feet/mile in the northeast of the field to 60 feet/mile in the southwest portion of the field. The varying thickness of the net productive formation is shown on Exhibit VI B. The trend of the sand to disappear as a productive formation to the northeast and east is indicated, and a tendency to become progressively thinner to

the south-west until it is no longer economically productive. These trends are further demonstrated by a southwest-northeast cross section shown in Exhibit VI C.

Due to the above mentioned dip, the Cardium is encountered at depths varying from 4600 to 5800 feet across the field.

It is necessary to establish, from an engineering standpoint, certain limits within which the sand characteristics would be considered to have economic possibilities. These limits are set by the porosity and permeability of the sand, giving a minimum figure of 0.1 millidarcy permeability and 9.0% porosity. The reservoir did not originally contain free gas nor has the oil column been found to be underlain by water. The oil was at a pressure above that at which the gas would come out of solution from the oil. The original reservoir pressure at a datum of 2300 feet subsea was about 2740 psig. The pressure at which the gas comes out of solution in the oil varies, but averages 1760 psig based on the analyses of samples collected at different points in the field. The gravity of the oil varies over a range of several degrees, with an average of 37.1^{o} API. The formation water, generally considered unproducible, is low, and an average figure for the field has been reported to be 10.5%. The average producing gas-oil ratio during the first six months production for various areas showed some

variation, but the majority of the central part of the field gave an average producing gas-oil ratio of less than 500 standard cubic feet per barrel.

The viscosity of the oil in the reservoir is fairly low and is around 1.2 centipoises at reservoir pressure and temperature. A survey of the whole field area, comprising some 370,000 acres, has indicated that there are 295,000 acres which may presently be considered to be proven as economically productive. This proven area has the following average sand characteristics:

Effective formation thickness . . .	19 feet
Porosity	14.2%
Interstitial Water	10.5%
Shrinkage Factor	0.76

These factors indicate that there were originally 4,200 million barrels of stock tank oil in place attributable to the said 295,000 proven acres.

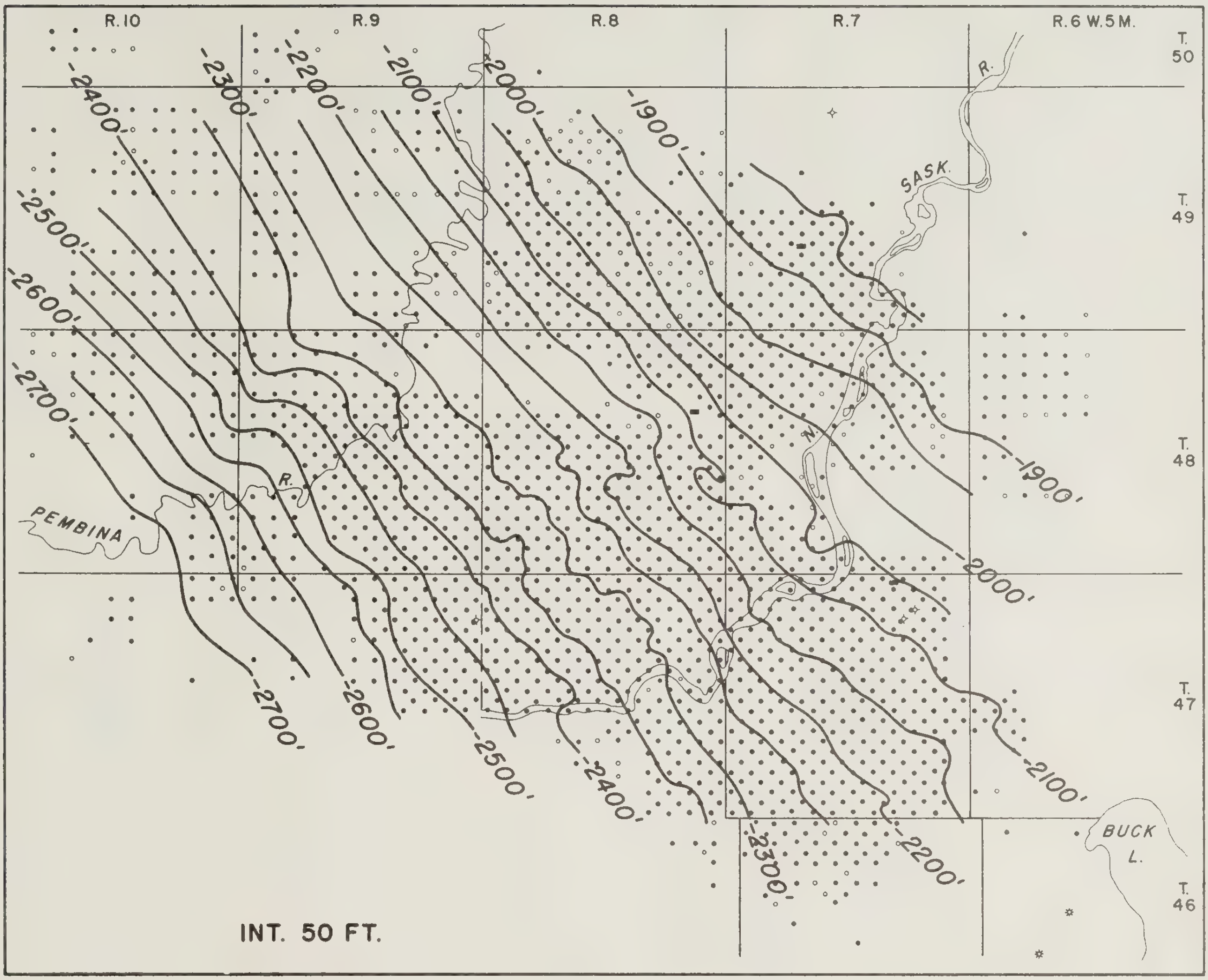


EXHIBIT VI A

CONTOURS ON TOP OF POROSITY

PEMBINA FIELD

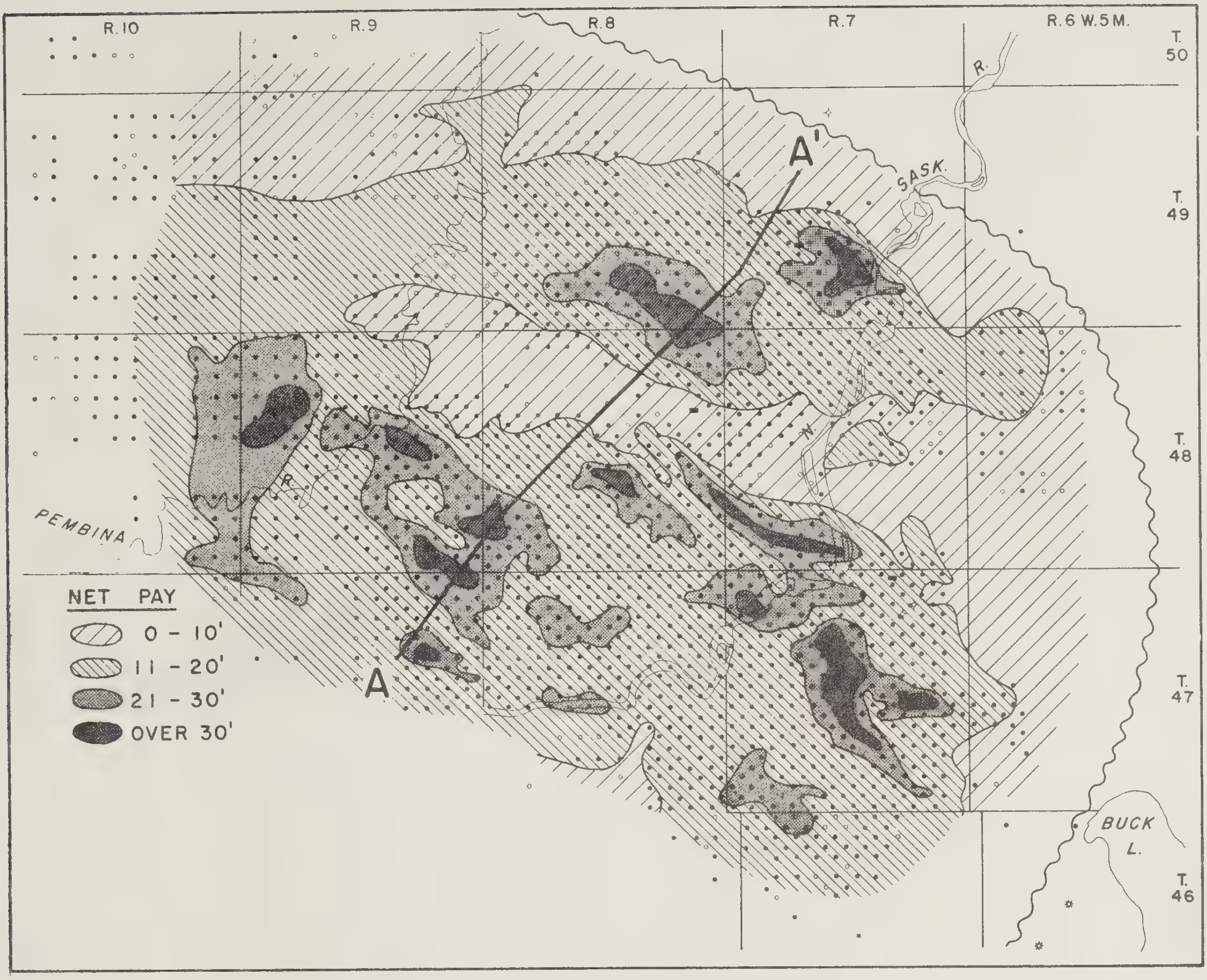


EXHIBIT VI B

ISOPACHOUS MAP

PEMBINA FIELD

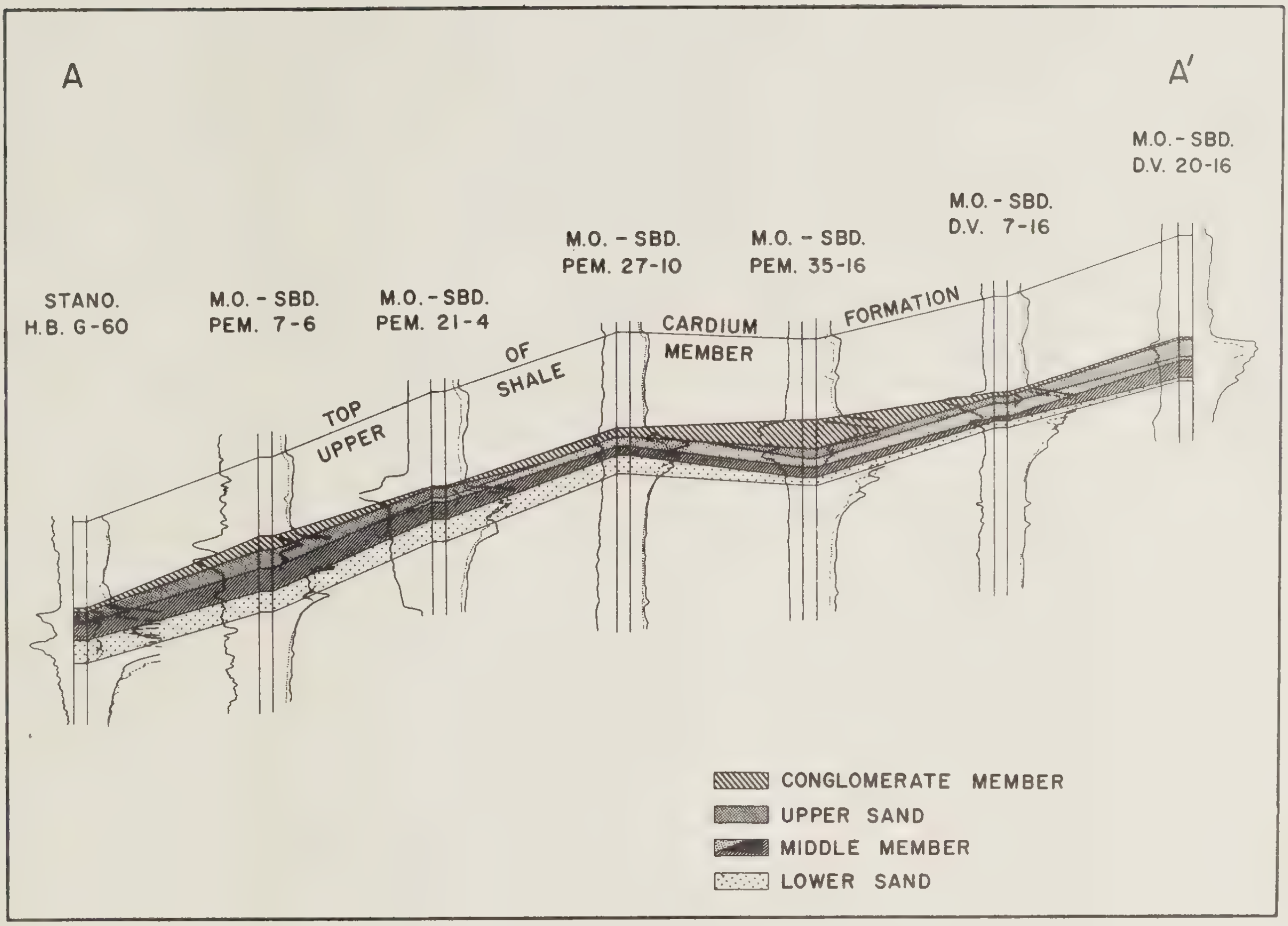


EXHIBIT VI C

DIP CROSS - SECTION

PEMBINA FIELD

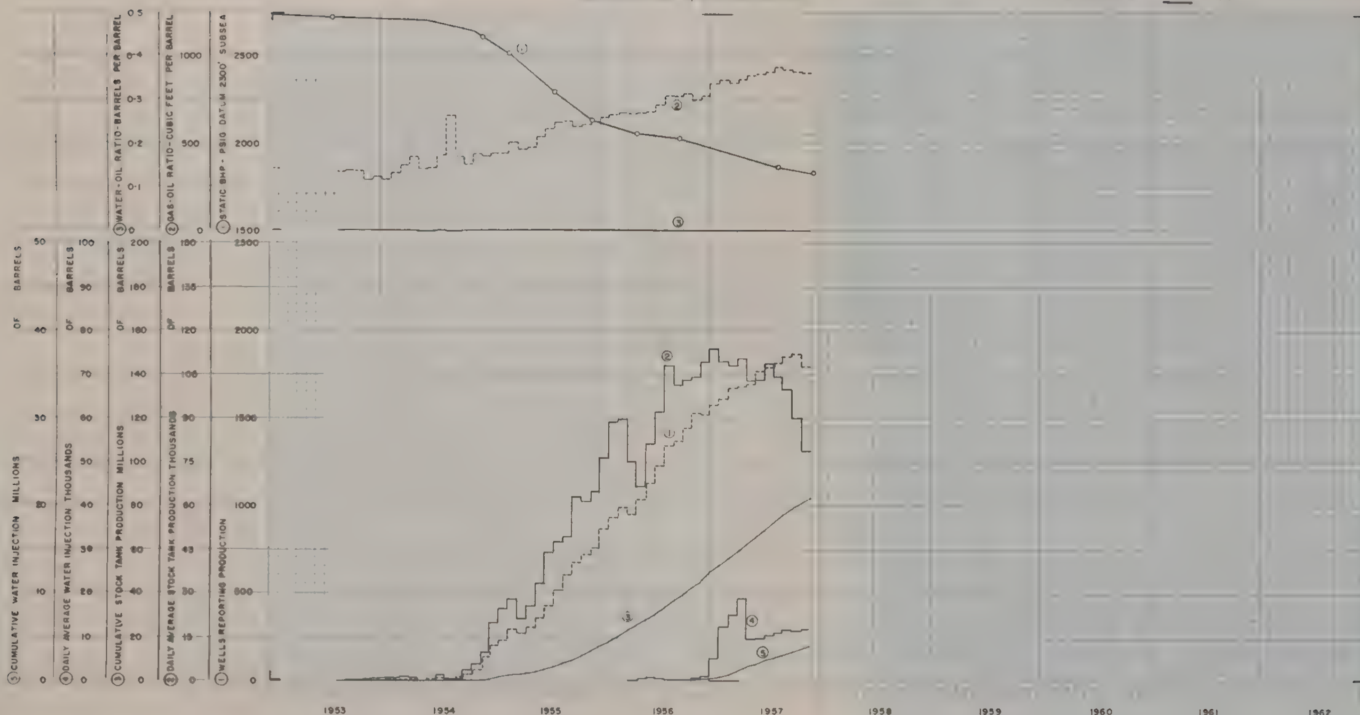
SECTION VII

Reservoir Performance

Since its inception to November, 1957, the Cardium Reservoir of the Pembina Field has performed as shown on Exhibit VII A. The cumulative production of oil from 2075 wells in the period July, 1953 to December, 1957, is 85,970,000 barrels. During this period of oil production, there has been a moderate and steady increase in gas production from approximately 400 standard cubic feet of gas per barrel of produced oil in the initial phases of production to the December, 1957, average of 904 standard cubic feet per barrel of produced oil. The reservoir pressure has declined from its initial 2740 psig to the October, 1957, average of 2025 psig measured at a datum of 2300 feet below sea level. This performance is normal and anticipated for this type of reservoir.

PEMBINA FIELD
PEMBINA CARDIUM POOL

EXHIBIT VII - A



SECTION VIII

Primary Production

The term "primary drive" is applied in the oil industry to the various types of mechanisms by which an oil or gas reservoir is produced when using only the energy available in the reservoir. If the producing mechanism is changed by the injection of gases or other fluids into the reservoir to increase the recovery, or the rate of production, the reservoir is no longer considered to be producing by primary drive. The term "primary production" is used to describe both the operation of a reservoir under primary drive, and the amount of oil and gas that will be recovered with the primary drive mechanism.

There are several different kinds of primary drive, such as dissolved gas expansion drive, water drive, expanding gas cap drive, and others. These primary drives vary widely in their individual effect on the producing rate and amount of oil or gas produced by a reservoir. It is generally necessary to analyse a reservoir thoroughly and obtain some production history, with attendant reservoir performance data, to determine the particular type of primary drive which is operating in that reservoir.

After detailed studies had been made and after some production history had been obtained, it was determined that the primary drive for the Pembina Cardium reservoir was the expansion of the oil followed by the type known as the dissolved gas expansion drive. Under this type of drive, oil is driven to the producing wells by the expansion of the oil and of the gas dissolved in the oil; the oil and gas remaining in the reservoir expand when oil and gas are removed from the reservoir through producing wells because their removal reduces the pressure in the reservoir. It is evident that the oil and gas expansion force is a progressively decreasing force throughout the producing life of a reservoir with this type of drive. A reservoir generally produces a much smaller amount of oil with an oil and dissolved gas expansion drive than it would if one of the other types of primary drive was operating the reservoir.

Due to variations in sand characteristics and oil characteristics throughout the widespread Pembina Cardium reservoir, it is indicated that under primary drive the recovery of the oil in place in various portions of the Pembina Field will vary from about 5% to about 20%, with the overall field average being about 12%.

In order to illustrate the economics of a typical producing operation in the Pembina Field under primary drive, and to permit a comparison with a subsequent section

in this submission dealing with pressure maintenance operations (Section IX), there is presented herewith a brief picture of the operation of a 160-acre tract in the 80-acre spacing area of the field, which tract has an assumed recovery of approximately 12% of the oil in place.

In order to acquire the 160-acre tract, an operator would have to obtain it either through the reservation and lease procedure previously mentioned or through purchase at a public sale of Crown acreage. The average purchase price of the Crown acreage sold at Pembina is approximately $1,200 per acre. Although it is difficult to assess the price of acreage obtained through the reservation and lease procedure, it is evident that a company employing this procedure must spend considerable amounts in obtaining and processing (including seismic work, geological studies and exploratory drilling), many unproductive reservations and leases, in order to obtain productive leases, and, in the final analysis, the productive leases must carry the load of all monies expended in the effort. It is the considered opinion, based on experience of the companies presenting this submission, that the price of $1,200 per acre is a close approximation of the cost of productive acreage at Pembina obtained through the reservation and lease procedure. Incidentally, the cost of $1,200 per acre is also a cost of approximately $0.57 per barrel of primary

oil reserves for the typical 160-acre tract considered herein, and this cost appears to be confirmed reasonably well by the cost of $0.50 per barrel acquisition cost for the Canadian oil industry as presented by the Canadian Petroleum Association in its submission to the Borden Commission. The total cost to the average operator, therefore, of acquiring a 160-acre productive tract in the Pembina Field is taken to be 160 x $1,200, or $192,000.

The operator is next faced with the necessity of drilling and equipping two wells. The average cost of drilling and equipping a well has been approximately $65,000. Each well logically must be assigned its share of costs for a tank battery, road facilities, housing for employees and other related investment costs. Total investment costs expended in the field to date on such facilities have been found to average approximately $25,000 per well. Investment for a pumping unit must also be made very early in the producing life of a well; this investment item averages $10,000 per well. The total of all these costs is $100,000 per well, or $200,000 for the two wells on the 160-acre tract.

In summary, it has been shown that the operator must invest approximately $392,000 on this 160-acre tract before commencing to obtain revenue from oil production.

The "average well" in the Pembina Field was completed in the middle of 1956, and this point was selected as the start of production for the typical 160-acre tract under consideration. The wells are predicted to have a producing life of approximately 18½ years, as shown on Exhibit VIII A, during part of which time they are being restricted in production by market outlet. During the life of the wells, they will produce a total of approximately 335,000 barrels of oil with a gross value, at an estimated average price of $2.61 per barrel, of $874,000. The operator, during this period, will pay to the Crown approximately $80,000 in royalty and will spend approximately $276,000 in operating costs, leaving a net income after deducting his initial investment and before taxes of approximately $126,000. In addition, the operator will obtain an estimated net income of $12,000, before taxes, from the gas produced in conjunction with the oil. This results in a total net income, before taxes, from both oil and gas, of $138,000 over the 18½ year life of the wells. The payout time, before taxes, of the initial investment is approximately 7 years and the annual rate of return on the initial investment, before taxes, about 7%. No attempt is made here to present the after tax picture for the operator of this typical tract because the tax position of all the operators in Pembina is so widely diversified that no tax position could be presented that would be representative.

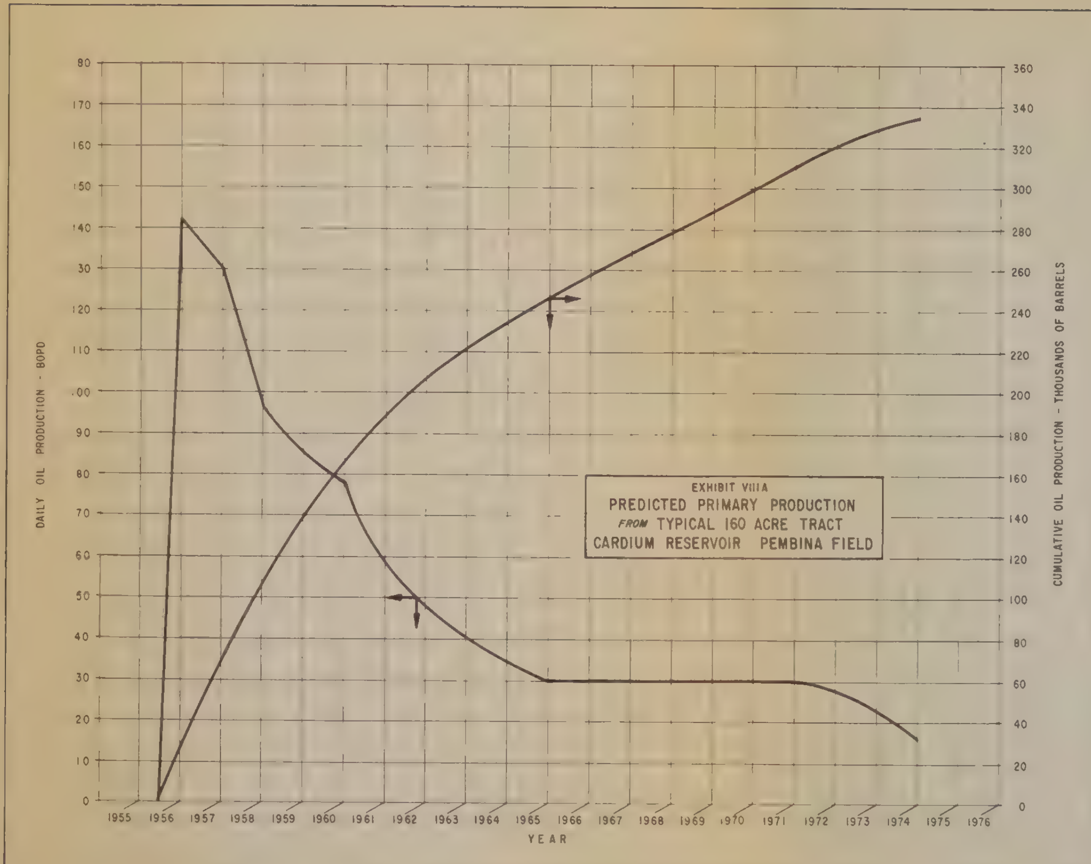


EXHIBIT VIII A
PREDICTED PRIMARY PRODUCTION
FROM TYPICAL 160 ACRE TRACT
CARDIUM RESERVOIR PEMBINA FIELD
DAILY OIL PRODUCTION - BOPD
CUMULATIVE OIL PRODUCTION - THOUSANDS OF BARRELS
YEAR
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SECTION IX

Pressure Maintenance

The low recovery efficiencies in withdrawal of oil from the reservoir which a dissolved gas expansion drive mechanism would give, was foreseen at an early date in the history of the field. The major operators in the field, therefore, started intensive research programs to analyse the data obtained from the formation cores and fluid analyses, and investigated in their laboratories the applicability, for the Pembina Cardium reservoir, of various proven methods of increasing the recovery of oil.

The results of this laboratory work, which had been started early in 1955, indicated that water flood operations could be economically attractive in the major part of the field, whereas gas flooding would have economic application in restricted parts of the field.

In April, 1956, one of the major operators initiated water injection tests into the Cardium reservoir. After several months of testing had demonstrated that water in satisfactory quantities could be injected, this project was expanded to include eight injection wells. A second major operator initiated water flood operations in November, 1956 and extended the flood to cover 13,440 acres, or nearly all its holdings. A third major operator initiated

water flood operations in December, 1956 with a pilot scheme in which water was injected into six wells. Also, other operators commenced injection in 1957, and by the end of that year approximately 25,000 acres were under flood.

The three major operators mentioned above had made extensive studies over a total of approximately 22,400 acres of properties which they held,and which they considered to be the most suitable for water flooding. These studies indicated that they could expect, for the properties considered, a 2 to 3 fold increase in oil recovery through pressure maintenance by water flooding as compared to expected oil recovery by primary methods. The operators, with the approval of the Conservation Board, established a standard pattern of flooding which would convert each alternate line of wells on an 80-acre spacing pattern into water injection wells, as shown for a section of the field on Exhibit IX A. The supply of water was a problem which required very careful analysis. It was found by the drilling of a large number of test wells that suitable underground water supplies were limited in some sections of the field. Therefore, an alternative supply from the North Saskatchewan River was studied, and after extensive investigation, it was determined that sufficient quantities of water could be obtained from the river and subjected to treatment which would render it suitable for injection into the Cardium reservoir.

As a result of this work, two basic methods of water supply have been evolved:

a. Each injection well is supplied by an adjoining shallow water well, from which the water is pumped, treated as necessary, and pumped under pressure down the injection well into the formation.

b. Water is collected from the river, treated and distributed to water injection stations where it is pumped under pressure through line to individual injection wells.

In the latter case, the nature of the water and its content of impurities has necessitated the construction of very costly water treatment plants. In addition, the distance of the river from the acreage served has necessitated the construction of extensive and costly water distribution systems. Corrosion protection measures and the burying of lines to abnormal depths to prevent freezing, in some instances over 8 feet, have contributed significantly to the cost of the systems.

The various water flood projects installed to date are proceeding satisfactorily. Performance of the pilots and the full scale projects to date has indicated, among other things, that, for the areas at present being flooded:

(1) A satisfactory flood mechanism can be established using water to raise or maintain the pressure in the formation, and thereby prevent unnecessary gas coming out of solution in the reservoir with an attendant wastage of natural energy, and

(2) With careful control there is no early breakthrough of water from the injection wells into the producing wells.

Knowledge of the detailed characteristics of an underground reservoir is always very little in view of the fact that only the formation characteristics in the well bore itself (a cylinder of about 7 to 9 inches in diameter), are known. Data obtained from a close analysis of the formation encountered in this cylinder, combined with information obtained from surrounding wells, is used to deduce the nature of the reservoir for an entire 80 or 160-acre area.

Since the formation characteristics change from point to point, and since the wells have had to be fractured to increase their capacity, there are a number of unknown factors in the Pembina Cardium reservoir which can drastically affect the efficiency of fluid injection projects; consequently, it is only by actual field operation that the efficiency of the projects can be determined.

Although laboratory investigations have indicated that the oil recovery from the Pembina Cardium reservoir can be considerably increased by water flood operations, and although performance to date of the pilots and full scale flood projects tends to substantiate the laboratory findings, a very appreciable amount of additional performance data will be required to establish that the flood operations will perform as expected. In view of the factors discussed above, it should be recognized that the operators have embarked on a costly high risk venture in an attempt to increase recovery from the Pembina Cardium reservoir.

A pressure maintenance project by water flooding in an area of the Pembina Field which has already been fully developed for production, and which does not require the drilling of injection wells, since one well in every two will be converted to a water injection well, has been estimated to cost about $160 per acre with all facilities. These include the water supply with injection lines and pumps, and equipment to treat any produced water.

Based upon present understanding of the reservoir, it is estimated that there are about 140,000 acres susceptible to water flooding, which would cost about $22.5 million for the initial installation. It is considered probable that the initially installed facilities will have to be replaced completely every 15 years during the life of the flood.

In Section VIII of this submission, there was presented a brief picture of the primary operation of a 160-acre tract in the 80-acre spacing area of the field. There is presented herewith a brief picture of this same typical tract produced under the operation of pressure maintenance by water flooding. Under this operation, one of the two producing wells on the tract is converted to a water injection well, and the remaining well is used to produce all the recoverable oil under the tract.

It is arbitrarily assumed that the typical tract which has been selected for this study will have an ultimate recovery of 30% of the oil in place for this operation, and based upon a starting date of January, 1959, as being the average for all pressure maintenance schemes, it is estimated that about 36 years future life will be required. This life estimate is based on the present provincial allowables, the existing proration system and predicted well producing capacities. The predicted production history of this tract is shown on Exhibit IX B.

The other factors which have been used are:

a. A similar basis of well costs and land acquisition as shown for wells under primary operations.

b. A cost of $160 per acre for the installation of the pressure maintenance facilities in an area which has been fully developed for production. This amounts to $26,000 for a 160-acre tract.

c. The replacement of all tangible water flood and operating equipment every 15 years during the life of the flood.

d. An operating cost per year for each producing well and each injection well similar to that shown under primary operations.

e. An estimated average price of oil of $2.61 per barrel.

Using the factors set out above, it is indicated that the said tract will produce during its life a total of 829,000 barrels of oil with a gross value of $2,164,000. The operator, during this period will pay to the Crown approximately $ 220,000 in royalty and will spend approximately $535,000 in operating costs, leaving a net income after deducting his initial and replacement investment, but before taxes, of approximately $892,000. In addition, the operator will net an estimated income of $12,000, before taxes, from the gas produced in conjunction with the oil. This results in a total net income, before taxes, from both oil and gas, of $904,000 over the 38½ year life of the tract. The payout time, before taxes, of the initial investment is approximately 5.3 years and the annual rate of return on the initial and replacement investment, before taxes, is about 17.7%. As in the case for primary operation, no attempt is made here to present the after tax

picture for the operator of this typical tract because the tax picture of all the operators in Pembina is so widely diversified that no tax position could be presented that would be representative.

In view of the wide range of reservoir conditions which exist in the Pembina Field it has been previously estimated that less than half of the ultimate developed area will be adaptable to pressure maintenance by water injection.

Furthermore, in the area of pressure maintenance operations there will be a wide variation in the degree of response to water injection such that the financial return for various properties will be both less than, and in some cases greater than, that estimated for the above typical tract.

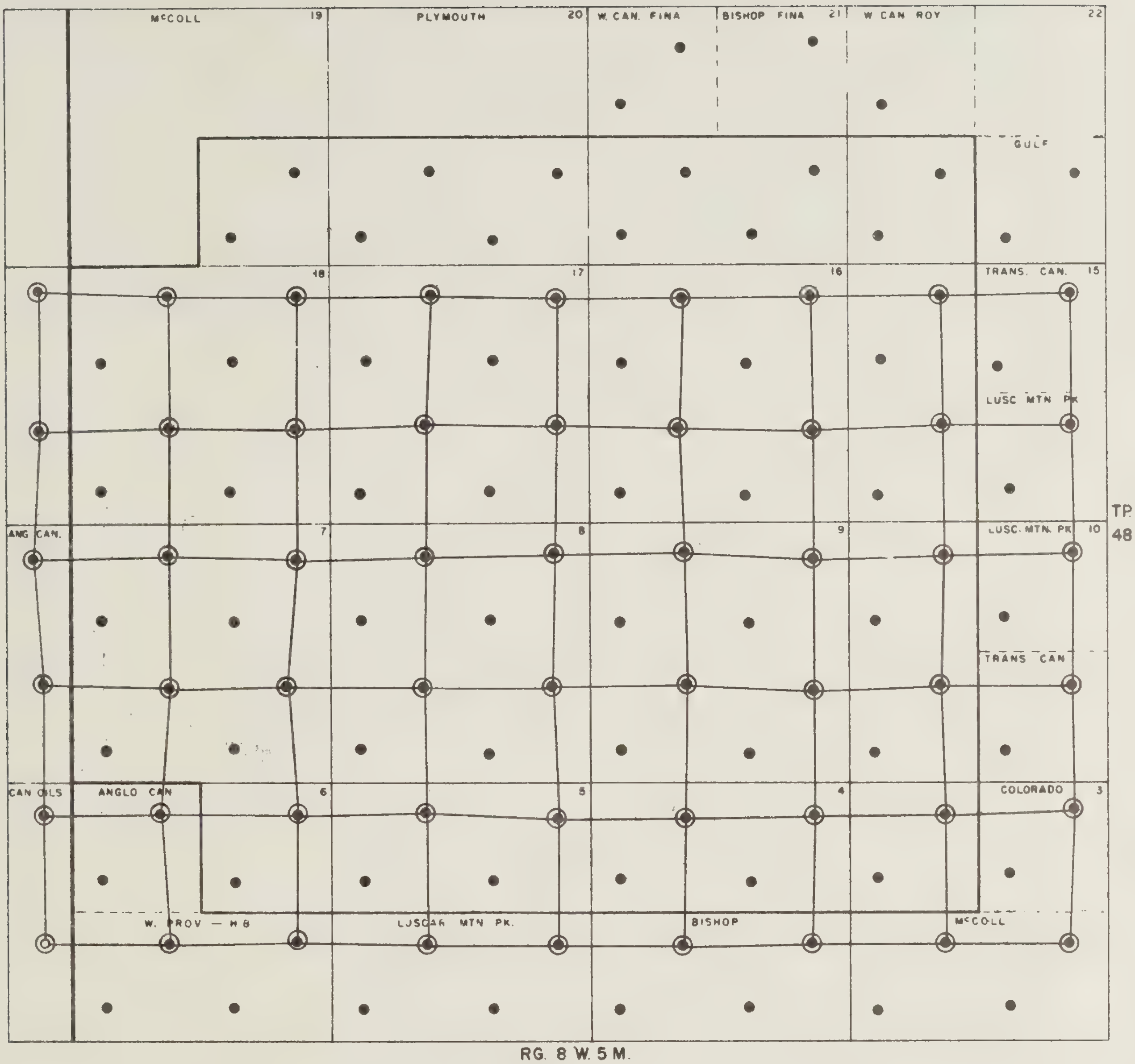


EXHIBIT IX A

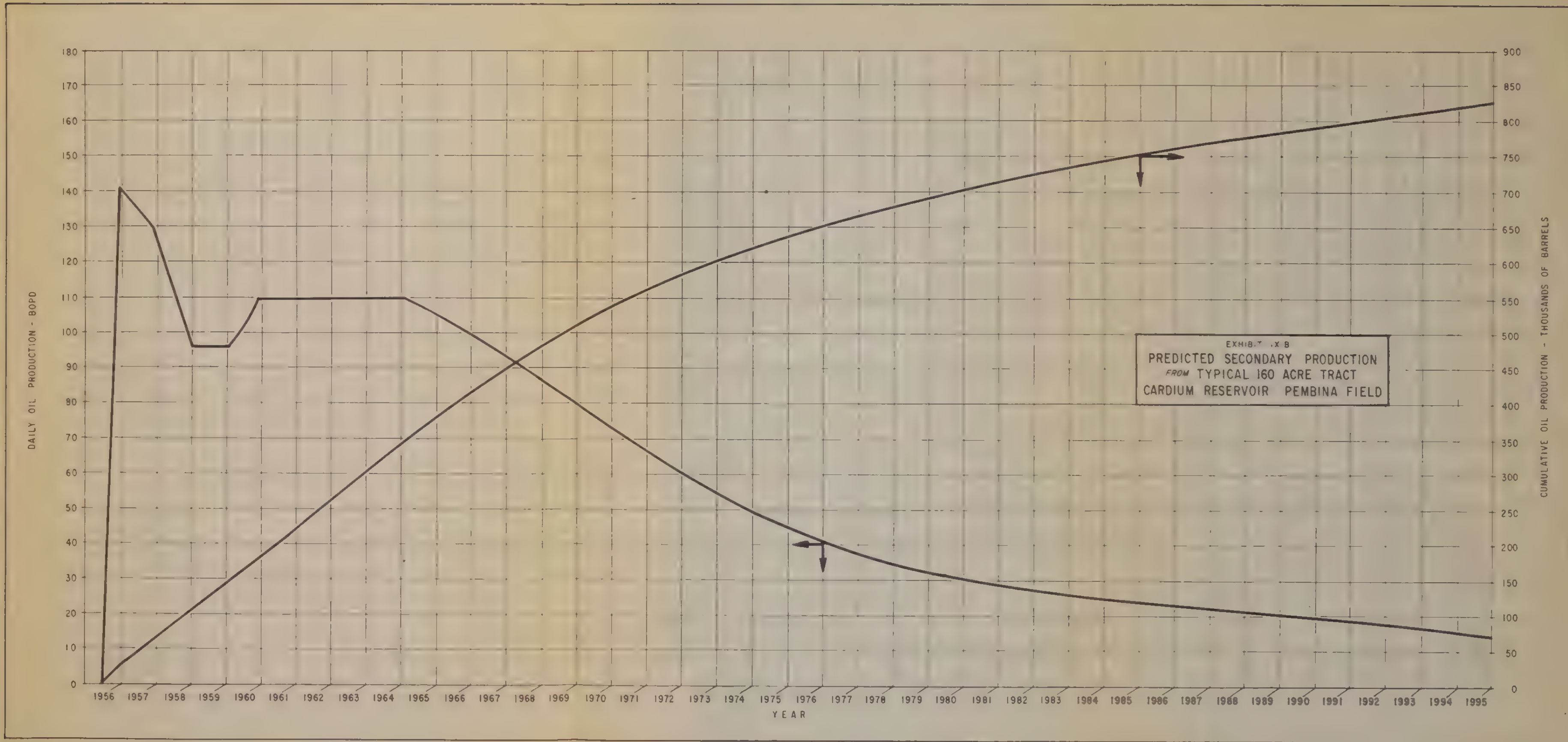
WATER INJECTION PATTERN

FIVE SPOT

PEMBINA FIELD

● PRODUCING WELL

◎ INJECTION WELL


EXHIB.T .X B
PREDICTED SECONDARY PRODUCTION
FROM TYPICAL 160 ACRE TRACT
CARDIUM RESERVOIR PEMBINA FIELD
DAILY OIL PRODUCTION - BOPD
CUMULATIVE OIL PRODUCTION - THOUSANDS OF BARRELS
YEAR
0 10 20 30 40 50 60 70 80 90 100 110 120 130 140 150 160 170 180
0 50 100 150 200 250 300 350 400 450 500 550 600 650 700 750 800 850 900
1956 1957 1958 1959 1960 1961 1962 1963 1964 1965 1966 1967 1968 1969 1970 1971 1972 1973 1974 1975 1976 1977 1978 1979 1980 1981 1982 1983 1984 1985 1986 1987 1988 1989 1990 1991 1992 1993 1994 1995

SECTION X

Gas Conservation

Introduction:

Serious consideration was first given the matter of gas conservation in the Pembina Field during the latter part of 1955. Subsequently, various plans of conserving gas were evaluated by the Pembina Operators, and these evaluations culminated in the Operators adopting a plan which received approval by the Oil and Gas Conservation Board in August, 1957. The approved plan is currently under construction and is scheduled to be placed in operation by about November 1, 1958.

The Pembina gas conservation project is by far the largest project of its kind yet instituted in Canada. As a matter of fact, it is, in many respects the largest such project ever instituted in North America. Considering the magnitude of the project and the various problems associated therewith, as hereinafter discussed, it will be appreciated that the Pembina project, scheduled to be placed in operation only three years from inception, is a notable example of the cooperative efforts of the producing segment of the industry and conservation authorities.

It is the purpose of the discussion which follows to provide an insight to the various events which occurred

relative to this matter; the problems with which the Operators were confronted; the manner in which these problems were resolved; the description of the plan which was adopted; the reasons for its adoption; and, pertinent financial aspects of the plan.

General:

It is recognized by the industry and by the conservation authorities that early in the producing life of an oil field a certain amount of gas wastage must be tolerated. However, they recognize that at such time as an oil field has been reasonably delineated and sufficient producing history has been obtained to permit a reasonably accurate forecast of gas production, consideration must be given to the economic feasibility of conserving the gas.

By the latter part of 1955 some 685 wells in the Pembina Field were on production. While the field was then only partially developed, development had proceeded to the point that Pembina was recognized as one of the major oil and gas reserves in Western Canada. At that time, all gas produced in conjunction with oil, over and above that required for lease fuel, was being flared -- averaging about 38 million cubic feet per day in October of that year.

Initial Discussions With Conservation Board:

The Oil and Gas Conservation Board, in October of 1955, advised the Operators through the Pembina Operators Committee, that it desired to meet with them to discuss the matter of gas conservation in the Pembina Field.

At a meeting of November 8, 1955, the Board reviewed with the Pembina Operators a preliminary study of the economics of conserving gas which had been prepared by the Board's staff. On the basis of this study, which, of necessity, was predicated on numerous assumptions, the Board concluded that a gas conservation might be economically feasible. The Operators were, therefore, informed that detailed studies should be initiated immediately to determine whether a gas conservation project would be reasonably economic -- all to the end that if feasible; an acceptable plan could be implemented early in the life of the field.

The Operators advised that they had given the matter some consideration and agreed that they would undertake the suggested detailed studies.

The Operators then outlined to the Board the comprehensive nature of such studies and the factors, as listed below, that would require detailed investigation before a realistic plan could be formulated:

1. Markets:

   (a) For Residue Gas -- Ascertain possible outlets, saleable quantities, quality, delivery conditions and prices.

   (b) For Liquid Products -- Ascertain to what extent the LPG's and natural gasoline might be marketed, probable methods of transportation and selling prices.

2. Storage:

   In anticipation that markets would not exist for all of the available liquid products and residue gas, investigate:

   (a) Possible location of a suitable storage reservoir.

   (b) The economic aspects of providing storage and probable costs of marketing stored products in the future.

3. Quantities of casinghead gas to be handled which would depend upon:

   (a) The anticipated oil producing rates from the field over an extended period.

   (b) The trend of future gas oil ratios (GOR's) throughout the field.

4. Economics of alternate plans for gathering and processing the produced casinghead gas.

The Operators then apprised the Board of some of the basic problems with which they were then confronted and which, to say the least, would serve to complicate their investigation of the above mentioned factors:

1. <u>Pressure Maintenance Prospects:</u>

   Several of the Operators had for some several months been studying the application of several pressure maintenance mechanisms in the Cardium reservoir. Such studies, covering both gas injection and water flood, were still in progress and no final conclusions were yet available or were likely to be available for several months.

   It was pointed out that should either gas injection and/or water flood appear feasible, on the basis of these studies, then it would be necessary to institute pilot tests in the field to determine the effectiveness of such operations. Should these pilot tests prove successful and dictate institution of some pressure maintenance program on a large scale, such would have a very significant effect on the quantities and quality of the casinghead gas produced, and in turn, on the availability for sale of liquid products and residue gas. In brief, it was pointed out that until the question of recovery of oil by pressure maintenance was reasonably resolved, it was difficult to anticipate the type and size of facilities required to gather and process the produced gas.

2. <u>Early Stage of Field Development:</u>

With regard to the matter of appraising means of conserving the produced gas or the initiation of a pressure maintenance program, it was emphasized that the field was at that time only about 1% depleted on the basis of expected recoverable reserves (or 1/5 of 1% of the estimated oil in place), and the field was only 15% developed. Consequently, the Operators were still in the early stages of collecting data and analyzing reservoir characteristics. This matter was further complicated due to the large amounts of acreage still held in the field by the Crown. With this situation existing, studies were handicapped because the free exchange of information between Operators was not possible while bidding for the purchase of Crown acreage was still in progress.

3. <u>Shortage of Technical Personnel:</u>

Inasmuch as the operating companies had not, to date, been engaged in the gas business in Canada to any great extent, there was a shortage, within the local organization of most of these companies, of personnel that possessed the necessary qualifications to handle a gas conservation project of this magnitude. Consequently, it would be necessary that additional personnel be obtained in the near future, and, to some

extent, draw upon the talents of other qualified personnel which were located in the offices of affiliated companies outside of Canada.

The Board indicated that it was appreciative of the problems and they recognized that a year or so might be required to properly resolve these matters. However, the Board emphasized that its prime concern was that the Operators make a concerted effort to study the matter of gas conservation. It was agreed that the Operators would submit to the Board in approximately six months a preliminary report on their progress in these matters.

Action Taken by Operators:

Immediately following the November meeting with the Conservation Board, the Pembina Operators Committee proceeded to formulate plans to study the conservation of gas. On December 6, 1955, three sub-committees were organized to undertake the necessary studies. These sub-committees, together with their duties and responsibilities, are listed below:

Reservoir Working Sub-Committee: This committee was directed to obtain the necessary reservoir data to prepare a study of gas reserves and gas production from the Cardium reservoir. It was also directed to evaluate, to the extent possible, the effect that various pressure maintenance programs, currently being studied by certain

of the Operators, might have on the ultimate recoverable gas reserves and production rates.

Gas Utilization Sub-Committee: This committee was divided into two sections, one to operate in Dallas, Texas, and the other section to operate in Calgary. The former section was directed to undertake an evaluation of laboratory analyses of gas and oil samples and the preparation of preliminary designs and cost estimates of process facilities. The latter section was directed to undertake the design of alternate plans for gathering and compression of the gas and the estimated cost thereof.

Steering Committee: The prime function of this committee was to provide management level guidance and to co-ordinate the activities of the Reservoir Working Sub-Committee and the Gas Utilization Sub-Committee. It was also the responsibility of this committee to investigate possible markets for residue gas and liquid products and to interest outside parties in undertaking the conservation of Pembina gas on behalf of the Operators. This committee was also charged with the responsibility of producing the necessary progress and final reports on the over-all studies to the Pembina Operators Committee.

Each of the foregoing committees was comprised of six to ten members representing, in total, about twelve Operators, which were both large and small holders of acreage in the Pembina Field.

Resume of Activities:

The Steering Committee made several contacts which indicated that several prospective market outlets existed for substantial volumes of Pembina residue gas. It was necessary, however, that further investigation of this matter be deferred, pending completion of reservoir studies which would reflect more accurately the volumes of gas which might be available for sale. For the same reason, investigation of market outlets for liquid products was deferred.

In order for the Reservoir Working Sub-Committee to develop the data required by the Gas Utilization Sub-Committee, it was necessary that a generalized analysis of the Pembina Cardium reservoir be made. For the purpose of this study, all Operators were requested to furnish all pertinent reservoir data applicable to their respective blocks of acreage; forecast of production and development rates therefor; estimate of the practical separator operating conditions; anticipated fuel requirements, etc. In requesting these data, each Operator was advised that such data would be treated on a confidential basis.

This Sub-Committee met regularly during the succeeding months to make an evaluation of the gas reserves and rates of production under primary recovery conditions.

On May 2, 1956, the Operators submitted to the Board a report on the progress made to date on their studies, and advised that a formal report on gas reserves and rates of production under primary recovery conditions would be submitted in August, 1956. The Board was advised that during the course of the current studies it had become apparent that the institution of pressure maintenance programs in the Cardium reservoir was much nearer at hand than had been envisioned in November of 1955.

In this connection, it was pointed out that one Operator had requested the approval of a pressure maintenance program which was to be the subject of a public hearing before the Board on May 15. Another major Operator had drilled an injection well and was currently studying injectivity rates, while a third Operator had been studying the question intensively and would probably request permission of the Board to make injection tests very shortly.

In view of this situation, the Board was advised that it appeared the primary recovery report would not reflect the future production history of the Cardium reservoir for more than a year or so. This report would, however, provide a useful yardstick to measure the success of any major pressure maintenance program. Therefore, the Board

was advised that the Reservoir Working Sub-Committee had been instructed to follow their primary recovery study with another study on gas production rates taking into account that a sizeable portion of the Pembina Field would be produced under conditions of pressure maintenance, and that completion of this second study could be expected around the end of 1956.

In August, 1956, the report covering predicted gas production rates under primary operations was submitted to the Board. The report was reviewed at a meeting held on September 5, 1956, between the Operators and the Conservation Board, and a discussion was had of the work being done on the second report covering gas production rates under conditions of pressure maintenance. The Board stated its desire to meet with the Operators again in April, 1957, it having been agreed that the Operators would at that time be in a position to present a report showing the economic feasibility of gas conservation in the Pembina Field.

The Gas Utilization Sub-Committee, pending completion of gas production rate forecasts, concerned itself with the determination of gas compositions at various GOR's, using all available data and made arrangements for the collection of additional samples where deemed necessary. On the basis of these data, preliminary work was performed to determine the most practical type of processing plant to be employed. In addition, laboratory tests were performed

to determine such data as were required to appraise the effects of commingling natural gasoline with Pembina crude oil in a pipeline for movement to markets.

In January, 1957, the Reservoir Working Sub-Committee completed its study of the Cardium reservoir under conditions of pressure maintenance and compiled year-by-year forecasts of gas producing rates. The Gas Utilization Sub-Committee thereupon proceeded to evaluate alternate plans for gathering, compressing and processing Pembina gas as a jointly-owned undertaking by the Operators. Simultaneously, all pertinent data that had been developed were furnished to ten (10) outside parties who had expressed to the Steering Committee an interest in submitting a proposal to conserve the gas on behalf of the Pembina Operators. In anticipation that the Gas Utilization Sub-Committee would complete its studies by February 22, 1957, this date was established as the deadline for receipt of all third-party proposals. Upon receipt of proposals from four (4) of these parties the Gas Utilization Sub-Committee prepared comparative evaluations of such proposals and those prepared by the Sub-Committee.

These evaluations reflected that it was "reasonably economic" to conserve Pembina gas; and, based on all investigations conducted by the Steering Committee, it was recommended to the Pembina Operators Committee that a

third-party proposal for gas conservation be accepted. After considerable discussions at subsequent meetings of the Pembina Operators Committee, it was finally determined that Operators holding in excess of 80 per cent of the acreage supported the adoption of the plan recommended by the Steering Committee -- namely, the proposal submitted by Goliad Ltd. (hereinafter referred to as the Goliad Plan).

It should be appreciated that considering (a) the extreme diversity of ownership interest in the Pembina Field; (b) the widely different financial positions of such interest owners; and (c) the many uncertainties, then existing, relative to the types of pressure maintenance programs that might be placed in operation and the extent to which such operations might be adaptable to the Field, it was to be expected that opinion would differ as to which of the various plans would most satisfactorily meet the needs of the Operators as a whole.

The following factors are considered to have been of prime importance in bringing about the decision of the Operators to adopt the Goliad Plan:

1. Economic and Financing Aspects:

   Even though the evaluations reflected that the Operators might derive more revenue under a plan whereby the required facilities would be installed and operated at the joint expense of the Operators,

the revenue did not exceed that to be derived under the Goliad Plan, most economically attractive of the third-party plans (which required no capital investment on the part of the Operators) to the extent that the large investment on the part of the Operators was deemed justified. Further, it had been established that the individual financial positions of many of the smaller Operators, holding in the aggregate a sizeable interest in the Pembina Field, would not enable them to participate in a project required to be financed as a joint venture by the Operators.

2. Flexibility:

Having determined that an Operator-owned project was not feasible under the prevailing circumstances, the matter of flexibility of the various third-party proposals in meeting the operational requirements of the Operators was an all important factor. The Operators deemed it necessary that they retain full control over the disposition of residue gas in that it was impossible to ascertain, at that time, what quantities of residue gas might be required in connection with pressure maintenance projects which were still under study. That is to say, it was considered premature to make either a total or

partial dedication of their gas. Of all the third-party plans submitted, the Goliad Plan was deemed to provide the most flexibility in this respect.

It should be emphasized that the course of action adopted by the Operators in this particular instance was dictated by circumstances brought about by many related problems which usually are not present in other oil fields at the time a gas conservation project is under consideration. Consequently, the type of plan adopted at Pembina should not be considered "typical" of plans which might be instituted elsewhere.

As a matter of fact, even in the case of Pembina, one operator, due to its considerable acreage holding being consolidated in just one portion of the field, adopted a different plan for conserving gas produced in that portion of the field. This will be commented upon later.

Operators Submit Gas Conservation Plan to Conservation Board:

At a meeting held in April, 1957, the Pembina Operators presented a gas conservation plan (Goliad Plan), supported by holders of in excess of 80 percent of the acreage. After reviewing the matter, the Board advised that, in principle, it approved the plan, however, formal approval could be granted only after the engineering details had been submitted for its review and the entire matter was made the subject of a public hearing.

The Board advised further that in view of the fact the proposed plan did not have 100 percent support of the Operators, it would be necessary to issue a gas conservation order for the Pembina Field. They pointed out that the purpose of the gas conservation order was three-fold:

1. To provide a mechanism for exempting areas where it could be demonstrated that it was uneconomic to conserve gas.
2. To alert all Operators of the necessity for prompt and effective action.
3. To inform future new purchasers of Crown acreage of the conditions with regard to gas so that they could evaluate their position at the time of submitting bids on Crown acreage.

Accordingly, on May 6, 1957, the Board issued its Order No. GC-4 which provided that gas conservation should be in effect in the Pembina Field on and after November 1, 1958.

Board Formally Approves Gas Conservation Plan:

Following negotiations of necessary contracts between the respective Pembina Operators and Goliad Ltd., and the finalization of engineering details and other pertinent data, a public hearing was held before the Conservation Board on July 23, 1957, relative to the application for

approval of the proposed gas conservation plan. As a result of this hearing, the Board formally approved the Goliad Plan by issuance of its Order No. 107, dated August 2, 1957.

Description and Operation of Gas Conservation Plan:

A. General

During the initial design phases of the Goliad Plan it was found that due to the large areal extent of the field, it was desirable to divide the field into several areas for the gathering, compression, dehydration, and extraction of liquids from the casinghead gas. The field has been divided into nine areas as shown on the attached map, Exhibit X - A. Eight of these areas, Area I through Area VIII, embracing some 216,000 acres of the Pembina Field, are part of the Goliad Plan. The ninth area, which will not be part of the discussion that follows, contains some 21,000 acres, and is served by separate processing facilities similar in physical nature to the Goliad facilities described hereinafter. The plan for conserving gas in the ninth area is a joint-venture project on the part of the Operators involved.

B. Description of Physical Facilities:

The number and size of the areas were chosen only after careful study to determine an optimum size with due regard to initial investment required and operating costs.

In general, the areas conform to lease ownership and include producing properties of comparable characteristics and economic life. The field gas is gathered at a pressure of about 30 pounds per square inch from some 300 batteries through a network of pipelines serving each of the individual area processing plants. Here the gas is compressed, dehydrated, and the hydrocarbon liquids contained therein are removed by refrigerating the gas. After removal of the liquids, the gas is compressed further to a pressure of 950 pounds per square inch for delivery to a transmission line and/or return to the reservoir for recovery of additional oil.

The liquids, after removal from the gas, are pumped into a liquid gathering system, serving each of the areas, for delivery to a central liquids fractionation plant for further processing.

At the central fractionation plant, the unstabilized liquid stream is fractionated into saleable products of propane, iso-butane, normal butane, and a low vapor pressure natural gasoline.

1. Area Stations

The area processing plants vary in individual size from a small station having 3 compressor units, totalling 1980 horsepower, and 12.2 miles of gathering lines handling about 6,000 MCF/D of gas to a large station having

6 compressor units, totalling 3960 horsepower, and 56 miles of gathering lines handling about 14,000 MCF/D of gas. The eight area processing plants together have:

No. of Compressor Units	33
Installed Horsepower	21,780
Size of Gathering Lines	3" to 12"
Length of Gas Gathering Lines . .	270 miles

The gathering lines, if combined into a single line, would approximately extend from Calgary to Edmonton and back to Red Deer.

2. Liquid Gathering System

The liquid gathering system consists of 43 miles of 3-inch to 6-inch lines with major river crossings on both the Pembina and Saskatchewan Rivers.

3. Liquid Trunk Line

A liquid trunk line is to be constructed from the central fractionation plant to a loading rack which is to be located at a rail siding within 45 miles of the Pembina Field. It will be used to transport the propane and butanes to the loading rack for movement to market.

C. Operation of the Goliad Plan

Basically, the Goliad Plan provides for a third party to finance, design, construct, and own all of the facilities required for the conservation of gas in the field,

and to lease a portion of these facilities to the Operators for their use.

More specifically, the Goliad Plan functions as follows:

1. (a) The fractionation plant, the liquid gathering system to the plant, and the liquid trunk line is being financed, designed, built, owned and operated by Goliad Oil and Gas Company;

(b) Each gathering area facility is being financed, designed, built, and owned by a wholly-owned subsidiary of Goliad Ltd. and leased to the Operators within the individual gathering area, jointly and severally, and will be operated at cost by such subsidiary for the account of the area Operators.

(c) The lease of the gathering area facility is for a term of 18 years. For the first 10 years the annual rental will be equal to the income tax depreciation plus interest at 8% on the unamortized balance. For the remaining 8 years the rent will be sufficient to retire the balance of the cost in equal installments plus interest at 8% on the unamortized balance. The Operators in the respective areas cannot terminate this lease and are obligated, under any circumstances, to pay over the term thereof the rentals specified therein.

(d) The Operators in the individual gathering area at the end of the 10 years have an option to purchase from Goliad Ltd. the stock of the subsidiary owning the gathering area facilities.

2. The unstabilized liquids recovered in the area facility are sold to Goliad Oil and Gas Company for further processing and resale. For a period of fifteen years, the revenue to the Operators from the sale of liquids is determined by a formula based on the net re-sale value of all liquids recovered, the total gallons of liquids sold from the area, the total gallons of liquids sold from the entire Pembina Field, and until payout of the fractionation plant the receipts from a processing charge of 2¼¢/MCF of residue gas available from the gathering area facility. The formula is devised so as to return to Goliad Oil and Gas Company an essentially uniform annual income sufficient to retire in 5 years, after income taxes, its total investment in the central fractionation plant, liquid gathering system and liquid trunk line, together with all operating expenses. During the next 10 years, this annual income to Goliad is guaranteed by the Operators to the extent that said income is available from the sale of liquids. That is to say, Goliad will retain whatever portion, up to 100% of the revenue derived from the sale of liquids that is

necessary to maintain its established annual income. After the 15th year the net profits from the fractionation plant will be split 50-50 between Goliad and the Operators.

3. The residue gas available from the gathering area facility remains the property of the individual Area Operators to dispose of in whatever manner they deem to be in their best interests.

D. <u>Summary of Estimated Costs and Production Figures</u>

1. <u>Costs</u>

The cost of the Goliad Plan for conserving Pembina gas is estimated to be about $18,150,000. This estimate is divided as follows:

Area Facilities	$ 13,900,000
Central Fractionation Plant, Liquid Gathering System, and Liquid Trunk Line	$ 4,250,000
	$ 18,150,000

2. <u>Production</u>

During the first full year of operation, which will be 1959, it is estimated that the gas conservation facilities will process the following production:

Field Gas	85,750 MCF/D
Residue Gas	67,500 MCF/D
Propane	99,850 Imperial Gal/Day
Butanes	63,650 Imperial Gal/Day
Pentanes plus	43,790 Imperial Gal/Day

It should be emphasized that production during the initial year as well as subsequent years, will be determined primarily by the allowable oil producing rates and the effectiveness of the pressure maintenance projects instituted.

E. Disposition of Production

1. Residue Gas

The gas is to be sold to the Alberta and Southern Gas Company under a long term contract. Under the terms of this contract the gas will be made available to Northwestern Utilities Limited to serve their markets in the Edmonton Area, until the Alberta and Southern project is underway. However, should the Alberta and Southern project fail to materialize, said company may either continue to purchase the gas for resale to Northwestern Utilities or assign the contract to that company.

Northwestern Utilities is in the process of laying a line into the field and will gather the gas from each of the area processing plants and the central liquids fractionation plant for the account of Alberta and Southern.

2. Liquid Products

It is contemplated that the propane and butanes will be moved to market by either rail or truck; whereas

it is anticipated that the natural gasoline will be pumped into the crude oil pipeline system for delivery to a purchaser.

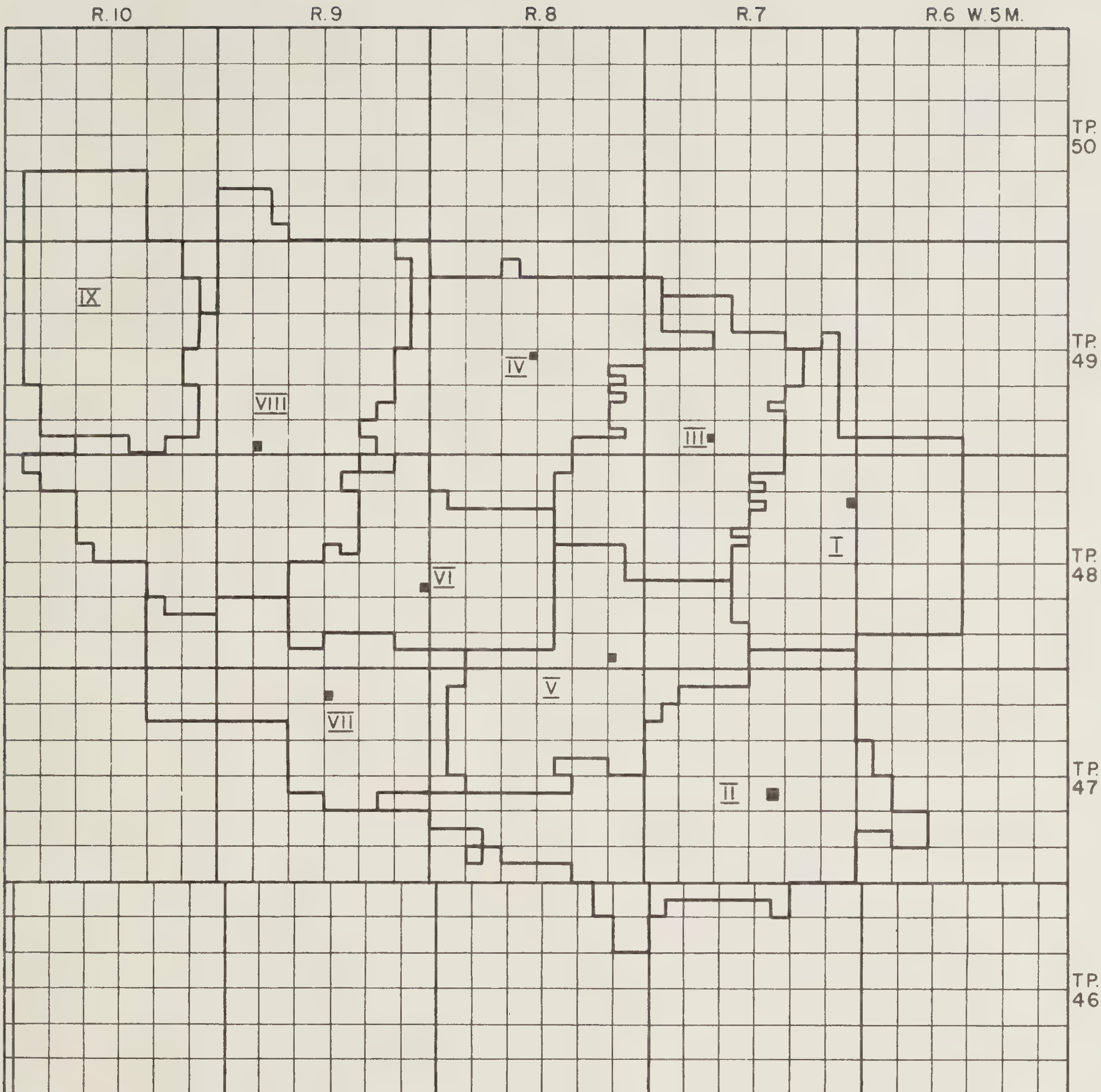
The ultimate market disposition for these products is not ascertainable at this time.

ESTIMATE OF REVENUES

A general idea of the financial aspects of the gas conservation project may be obtained from the results of economic studies that have been made. On the basis of these studies it is estimated that the project will generate a total of $66,793,000 from the sale of residue gas and liquid products. This income will be divided between the Operators and Goliad. Goliad will receive $21,480,000 gross, and the Operators will receive $45,313,000 gross. The Operators, from their share of the gross income, will be required to pay operating expenses and facility lease rentals amounting to $28,995,000. The net income to the Operators, before income taxes and royalty, will be $16,318,000.

An investigation was made to see what effect a depressed market in propane and butanes might have on the economics of the project. In this instance, it was assumed that only 75% of the propane production and 50% of the butanes production in the first year could be sold. It was further assumed that these sales quantities could be maintained during subsequent years, which, in effect, represents an increasing percentage of the plant production in

succeeding years. Under depressed market conditions, the total revenue would be $63,851,000; a decrease of $2,942,000 -- all of which comes out of the Operators' income. Since there would be no reduction in operating expenses, this would result in a net income, before income taxes and royalty, of only $13,376,000. It can be seen that should such a depressed market for these products prevail, the Operators' net income, before income taxes and royalty, would be reduced by 18 percent.



LEGEND

AREA DELINEATION

COMPRESSOR STATION LOCATION

EXHIBIT X – A

PEMBINA GAS CONSERVATION PROJECT

SCALE 1" = 4 MI.

SECTION XI

Summary

In summary, this brief has set forth the general history of the discovery and development of the Pembina Field and has dealt with the leasing pattern, with the construction of facilities, reservoir performance, matters of primary and pressure maintenance recovery of oil together with the problem of conservation of gas.

Throughout the brief, cost figures have been presented for the various phases of the operation. These in the aggregate present a huge total and, for convenience, are here recapitulated. It must be borne in mind that these figures, which are estimates only, are rounded into millions.

Costs in Millions

A. Direct Cost to Operators

Land Acquisition	324
Drilling and Primary Development . . .	207
Pressure Maintenance Facilities . . .	4
Gas Conservation Facilities	18
Total	553

B. Costs to Other Parties

Electrical Power Grid	4
Marketing Pipe Line	22
Independent Contractors and Service Companies. .	5
Total	31

The aforementioned costs are computed to 31 December, 1957, and will undoubtedly be increased, particularly as regards the land acquisition costs, which are estimated at a further 15 million dollars, further development costs at 40 million dollars, and the pressure maintenance costs estimated at a further 64 million dollars. In addition, a new gas line to the City of Edmonton will be constructed at an estimated cost of 16 million dollars. The ultimate expenditure by the Operators is therefore indicated to be approximately 675 million dollars.

Through the foregoing expenditures, it is estimated that there will be a total ultimate recovery from the Pembina Cardium reservoir of between 500 million barrels and 875 million barrels of oil over a total life of some 18½ to 38½ years.

In view of the variations in the reservoir conditions the financial rate of return to the various Operators will be both less than, and in some cases greater than, that indicated for the typical tract in the foregoing part of the submission.

All of which is respectfully submitted.

The aforementioned costs are computed to 31 December, 1957, and will undoubtedly be increased, particularly as regards the land acquisition costs, which are estimated at a further 13 million dollars, further development costs of 20 million dollars, and the pressure maintenance costs estimated at a further 64 million dollars. In addition, a new gas line to the City of Edmonton will be constructed at an estimated cost of 14 million dollars. The ultimate expenditure by the Operators is therefore calculated to be approximately 273 million dollars.

Through the foregoing expenditures, it is estimated that there will be a total ultimate recovery from the Pembina Cardium reservoirs of between 560 million barrels and 875 million barrels of oil over a total life of some 185 to 345 years.

In view of the variations in the reservoir conditions the Pembina net rate of return on the various operations will be both less than, and in some cases greater than, th indicated for the typical block in the foregoing part of th submission.

All of which is respectfully submitted.